Adams, Hope

From: Wessinger-Hill, JoAnne
Sent: Thursday, July 29, 2021 3:23 PM
To: Hall, Roger; Grube-Lybarker, Carri; John J. Pringle, Jr.; Heather Smith; Heather Smith; Pittman, Jenny; fellerbe@robinsongray.com; fellerbe@robinsongray.com; Nelson, Jeff; DeMarco, Tracy S.; Breitschwerdt, E. Brett; jennamcgrath@paulhastings.com; billdegrandis@paulhastings.com
Cc: PSC_Contact; Besley, Sharon
Subject: RE: Hearing Exhibit ? -- Judicial Notice? (Cross Examination Exhibit No. 2 Freund) -- DN 2020-263-E
Attachments: Cherokee Cross-Snider-002 - 2020 DEC IRP.pdf

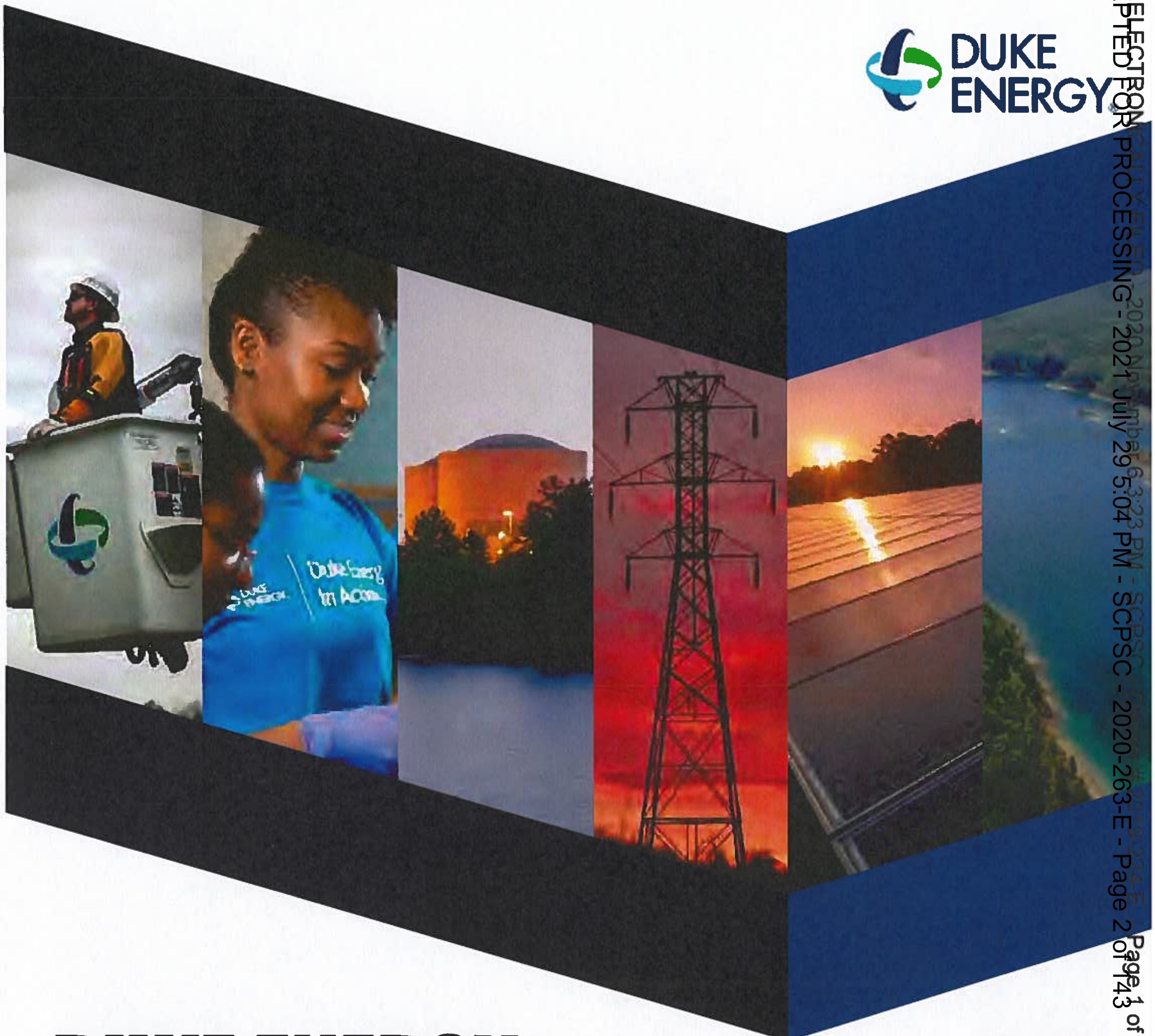
Parties:

Attached is a copy of the Cross Examination Exhibit Snider 002 regarding the Witness on the stand.

Jo Anne

C. Jo Anne Wessinger Hill, Esq.
General Counsel to the Commission
Public Service Commission
State of South Carolina
101 Executive Center Drive, Suite 100
Columbia, SC 29210
www.psc.sc.gov
Email: JoAnne.Hill@psc.sc.gov
803-896-5100 (main) | 803-896-5188 (f) | JoAnne.Hill@psc.sc.gov

The information contained in this e-mail message is public and will be filed in the Docketing Management System (DMS) for the corresponding docketed matter. Any responsive e-mail message by you should also be filed by you in the DMS for this matter. **If the reader of this message does not want certain information, which is meant to be discussed only between the parties and not Public Service Commission of South Carolina (Commission) staff, please do not use "reply all" to this message. Any e-mail message involving the Commission or Commission staff** is also subject to the provisions of Commission Order No. 2019-748 in Docket No. 2019-329-A; shall be published in the docket for this matter; and **should also be copied to all parties of record in the docket.** If you have received this communication in error, please immediately notify us by telephone at (803) 896-5100.



DUKE ENERGY CAROLINAS INTEGRATED RESOURCE PLAN

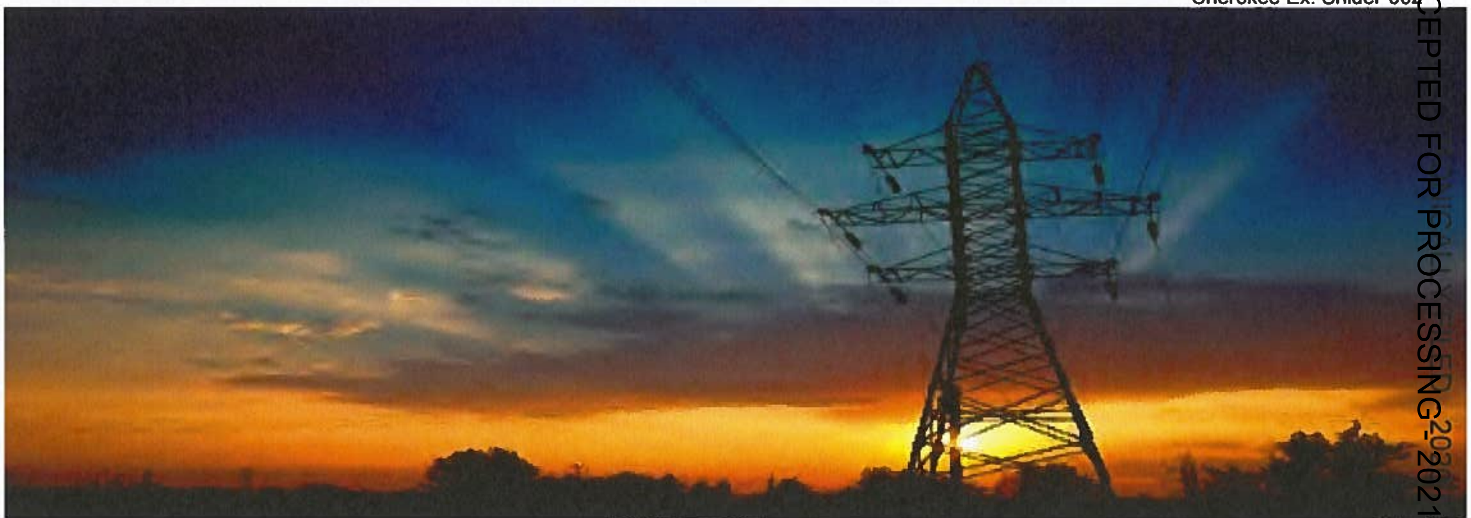
2020

Corrected 11.06.2020

DUKE ENERGY CAROLINAS 2020 INTEGRATED RESOURCE PLAN CONTENTS

Corrected 11.06.2020

ATTACHMENTS FILED AS SEPARATE DOCUMENTS:



1 EXECUTIVE SUMMARY

As one of the largest investor-owned utilities in the country, Duke Energy has a strong history of delivering affordable, reliable and increasingly cleaner energy to our customers. In planning for the future, the Company is transforming the way it does business by investing in increasingly cleaner resources, modernizing the grid and transforming the customer experience. Duke Energy Carolinas (DEC), a public utility subsidiary of Duke Energy, owns nuclear, coal, natural gas, renewables and hydroelectric generation. That diverse fuel mix provides about 23,200 megawatts (MW) of owned electricity capacity to 2.7 million customers in a 24,000 square-mile service area of North Carolina and South Carolina.

As required by North Carolina Utilities Commission (NCUC) Rule R8-60 and subsequent orders, the Public Service Commission of South Carolina (PSCSC) and The Energy Freedom Act (Act 62) in South Carolina, Duke Energy Carolinas is submitting its 2020 Integrated Resource Plan (IRP). The IRP balances resource adequacy and capacity to serve anticipated peak electrical load, consumer affordability and least cost, as well as compliance with applicable state and federal environmental regulations. The IRP details potential resource portfolios to match forecasted electricity requirements, including an appropriate reserve margin, to maintain system reliability for customers over the next 15 years. In addition to meeting regulatory and statutory obligations, the IRP is intended to provide insight into the Company's planning processes.

DEC operates as a single utility system across both states and is filing a single system IRP in both North Carolina and South Carolina. As such, the quantitative analysis contained in both the North Carolina and South Carolina filings is identical, although certain sections dealing with state-specific issues such as state renewable standards or environmental standards may be unique to individual

Corrected 11.06.2020

state requirements. The IRP to be filed in each state is identical in form and content. It is important to note that DEC cannot fulfill two different IRPs for one system. Accordingly, it is in customers' and the Company's interest that the resulting IRPs accepted or approved in each state are consistent with one another.

In alignment with the Company's climate strategy, input from a diverse range of stakeholders, and other policy initiatives, the 2020 IRP projects potential pathways for how the Company's resource portfolio may evolve over the 15-year period (2021 through 2035) based on current data and assumptions across a variety of scenarios. As a regulated utility, the Company is obligated to develop an IRP based on the policies in effect at that time. As such, the IRP includes a base plan without carbon policy that represents existing policies under least-cost planning principles. To show the impact potential new policies may have on future resource additions and in response to stakeholder feedback, the 2020 IRP also introduces a variety of portfolios that evaluate more aggressive carbon emission reduction targets. As described throughout the IRP, these portfolios have trade-offs between the pace of carbon reductions weighted against the associated cost and operational considerations. These portfolios will ultimately be shaped by the pace of carbon reduction targeted by future policies and the rate of maturation of new, clean technologies.

Inputs to the IRP modeling process, such as load forecasts, fuel and technology price curves and other factors are derived from multiple sources including third party providers such as Guidehouse, IHS, Burns and McDonnell, and other independent sources such as the Energy Information Administration (EIA) and National Renewable Energy Laboratory (NREL). These inputs reflect a "snapshot in time," and modeling results and resource portfolios will evolve over time as technology costs and load forecasts change. The plan includes different resource portfolios with different assumptions around coal retirement and carbon policy but recognizes that the modeling process is limited in its ability to consider all potential policy changes and lacks perfect foresight of other variables such as technology advancements and economic factors. To the extent these factors change over time, future resource plans will reflect those changes.

To further inform the Company's planning efforts, in 2019, Duke Energy contracted with NREL[1] to conduct a Carbon-Free Resource Integration Study[2] to evaluate the planning and operational

[1] "An industry-respected, leading research institution that advances the science and engineering of energy efficiency, sustainable transportation and renewable power technologies", www.nrel.gov.

[2] https://www.nrel.gov/grid/carbon-free-integration-study.html.

Corrected 11.06.2020

considerations of integrating increasing levels of carbon-free resources onto the Duke Energy Carolinas and Duke Energy Progress systems. Phase 1 of the study[3] has helped inform some of the renewable resource assumptions and reinforced the benefits that a diverse portfolio can provide when integrating carbon-free generation on the system. Phase 2 of the NREL study is underway now. This study is being informed by stakeholder input and will provide a more granular analysis to understand the integration, reliability and operational challenges and opportunities for integrating carbon-free resources and will inform future IRPs and planning efforts.

In accordance with North Carolina and South Carolina regulatory requirements, the 2020 IRP includes a most economic or "least-cost" portfolio, as well as multiple scenarios reflecting a range of potential future resource portfolios. These portfolios compare the carbon reduction trajectory, cost, operability and execution implications of each portfolio to support the regulatory process and inform public policy dialogue. In North Carolina, Duke Energy is an active participant in the state's Clean Energy Plan stakeholder process, which is evaluating policy pathways to achieve a 70% reduction in greenhouse gas emissions from 2005 levels by 2030 and carbon neutrality for the electric power sector by 2050. Accordingly, this year's IRP includes two resource portfolios that illustrate potential pathways to achieve 70% CO_2 reduction by 2030, though both scenarios would require supportive state policies in North Carolina and South Carolina. All portfolios keep Duke Energy on a trajectory to meet its near-term enterprise carbon-reduction goal of at least 50% by 2030 and long-term goal of net-zero by 2050. These portfolios would also enable the Company to retire all units that rely exclusively on coal by 2030. Looking beyond the planning horizon, the 2020 IRP includes a section that provides a qualitative overview of how technologies, analytical tools and processes, and the grid will need to evolve to achieve the Company's net-zero 2050 CO_2 goal. Duke Energy welcomes the opportunity to work constructively with policymakers and stakeholders to address technical and practical issues associated with these scenarios.

Act 62, which was signed into law in South Carolina on May 16, 2019, sets out minimum requirements for each utility's IRP. The 2020 IRP contains the necessary information required by Act 62, including, the utility's long-term forecast of sales and peak demand under various scenarios, projected energy purchased or produced by the utility from renewable energy resources, and a summary of the electrical transmission investments planned by the utility.

[3] https://www.nrel.gov/grid/carbon-free-integration-study.html.

Corrected 11.06.2020

The IRP also includes resource portfolios developed with the purpose of fairly evaluating the range of demand side, supply side, storage, and other technologies and services available to meet the utility's service obligations. Consistent with Act 62 and NC requirements, the IRP balances the following factors: resource adequacy and capacity to serve anticipated peak electrical load with applicable planning reserve margins; consumer affordability and least cost; compliance with applicable state and federal environmental regulations; power supply reliability; commodity price risks; and diversity of generation supply.

EXECUTIVE SUMMARY

Duke Energy's history of delivering reliable, affordable and increasingly cleaner energy to its customers in the Carolinas stems back to the early 1900's, when visionaries harnessed the natural resource of the Catawba River to develop an integrated system of hydropower plants that provided the electricity to attract new industries to the region. As the population in the Carolinas has grown and energy demand increased, the Company has worked collaboratively with customers and other stakeholders to invest in a diverse portfolio of generation resources, enabled by an increasingly resilient grid, to respond to the region's growing energy needs and economic growth.

Today, Duke Energy Carolinas (DEC) serves approximately 2.7 million customers. Over the 15-year planning horizon, the Company projects the addition of 560,000 new customers in DEC contributing to 1,650 MW of additional winter peak demand on the system. Even with the expansion of energy efficiency and demand reduction programs contributing to declining per capita energy usage, cumulative annual energy consumption is expected to grow by approximately 7,200 GWh between 2021 and 2035 due to the projected population and household growth that exceeds the national average. This represents an annual winter peak demand growth rate of 0.6% and an annual energy growth rate of 0.5%. In addition to growing demand, DEC is planning for the potential retirement of some of its older, less efficient generation resources, creating an additional need of at least 3,925 MW over the 15-year planning horizon. After accounting for the required reserve margin, approximately 4,600 MW of new resources are projected to be needed over the 15-year planning horizon.

While growing, DEC is projecting slightly lower load growth compared to the 2019 IRP due to a somewhat weaker economic outlook, the addition of 2019 peak history showing declines in commercial and Industrial energy sales, and other refinements to the forecasting inputs. Additionally,

Corrected 11.06.2020

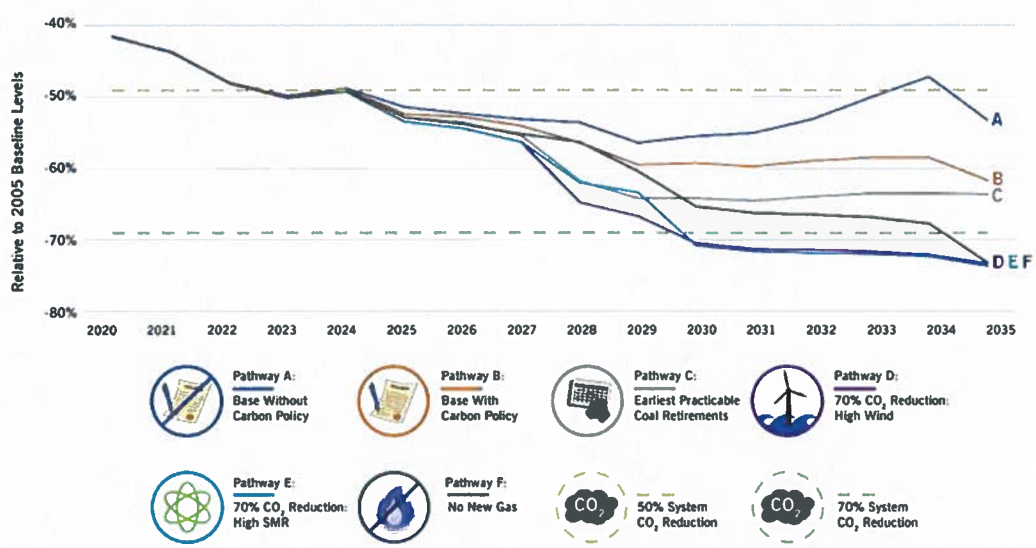
DUKE ENERGY CAROLINAS

due to the timing of the spring 2020 load forecast, which was developed using Moody's economic inputs as of January 2020, and the lack of relevant historical data upon which to base forecast adjustments, the potential impacts of COVID-19 are not incorporated in this forecast. Based on summer 2020 demand observations to date, however, it appears that the COVID-19 impact to peak demand is relatively insignificant. The Company will continue to monitor the impacts from the pandemic, including the higher residential demand and changing usage patterns, as well as the projected macroeconomic implications and incorporate changes to the long-term planning assumptions in future IRPs.

REDUCING GHG EMISSIONS

In 2019, Duke Energy announced a corporate commitment to reduce CO_2 emissions by at least 50% from 2005 levels by 2030, and to achieve net-zero by 2050. This is a shared goal important to the Company's customers and communities, many of whom have also developed their own clean energy initiatives. As one of the largest investor-owned utilities in the U.S., the goal to attain a net-zero carbon future represents one of the most significant reductions in CO_2 emissions in the U.S. power sector. The development of the Company's IRP and climate goals are complementary efforts, with the IRP serving as a road map that provides the analysis and stakeholder input that will be required to achieve carbon reductions over time. All pathways included in the 2020 IRP keep Duke Energy on a trajectory to meet its carbon goals over the 15-year planning horizon.

COMBINED CARBON REDUCTION BY SCENARIO



Corrected 11.06.2020

DEC has a strong historic commitment to carbon-free resources such as nuclear, hydro-electric and solar resources. In addition, as described in Appendix D, DEC provides customers with an expansive portfolio of energy efficiency and demand-side management program offerings. In total, DEC and Duke Energy Progress (DEP), through their Joint Dispatch Agreement (JDA), serve more than half of the energy needs of their customers with carbon free resources, making the region a national leader in carbon-free generation.

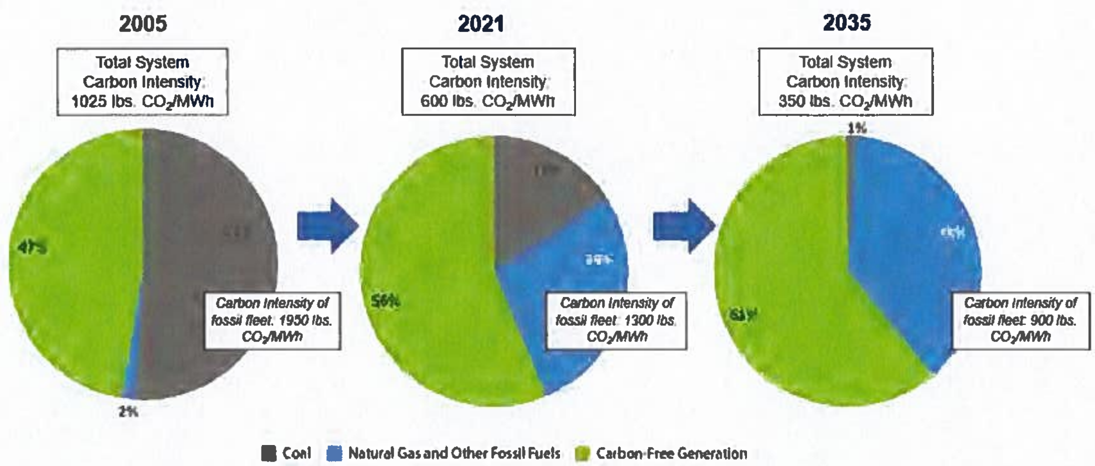
Combined, DEC and DEP operate six nuclear plants and 26 hydro-electric facilities in the Carolinas with winter capacities of over 11,000 MW and 3,400 MW respectively. In 2018, Duke Energy's nuclear fleet provided half of our customers' electricity in the Carolinas, avoiding the release of about 54 million tons of carbon dioxide, or equivalent to keeping more than 10 million passenger cars off the road. As the Company meets its customers' future energy needs and reduces its carbon footprint, it is seeking to renew the licenses of 11 nuclear units it operates at six plant sites in the Carolinas. This provides the option to operate these plants for an additional 20 years. In addition, DEC and DEP purchase or own approximately 4,000 MW of solar generation coming from approximately 1,000 solar facilities throughout the Carolinas. In DEC, where a large portion of energy has historically been sourced from carbon-free resources, the Company has reduced CO_2 emissions by 36% since 2005. In addition to a leadership position in absolute emission reductions, energy produced from the combined DEC/DEP fleet has one of the lowest carbon-intensities in the country. With a current CO_2 emissions rate of just over 600 pounds /megawatt-hour, the combined Carolinas' fleet ranks among the nation's top utilities for the provision of low carbon-intensive energy.[4] The following figure illustrates how the Company is building on its leadership position through the addition of carbon free resources such as solar and wind while also reducing the emissions profile and carbon intensity of remaining fossil generation by reducing dependence on coal and increasing utilization of more efficient, less carbon intense, natural gas resources.

[4] Source: MJ Bradley, "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States" – July 2020, p. 30.

DUKE ENERGY CAROLINAS

COMBINED SYSTEM CARBON REDUCTION TRAJECTORY (BASE CO_2)

THE COMBINED DEC / DEP FLEET IS A NATIONAL LEADER IN LOW CARBON INTENSITY ENERGY, WITH A CURRENT RATE 37% LOWER THAN THE INDUSTRY AVERAGE OF 957 LBS. CO_2/MWH[5]



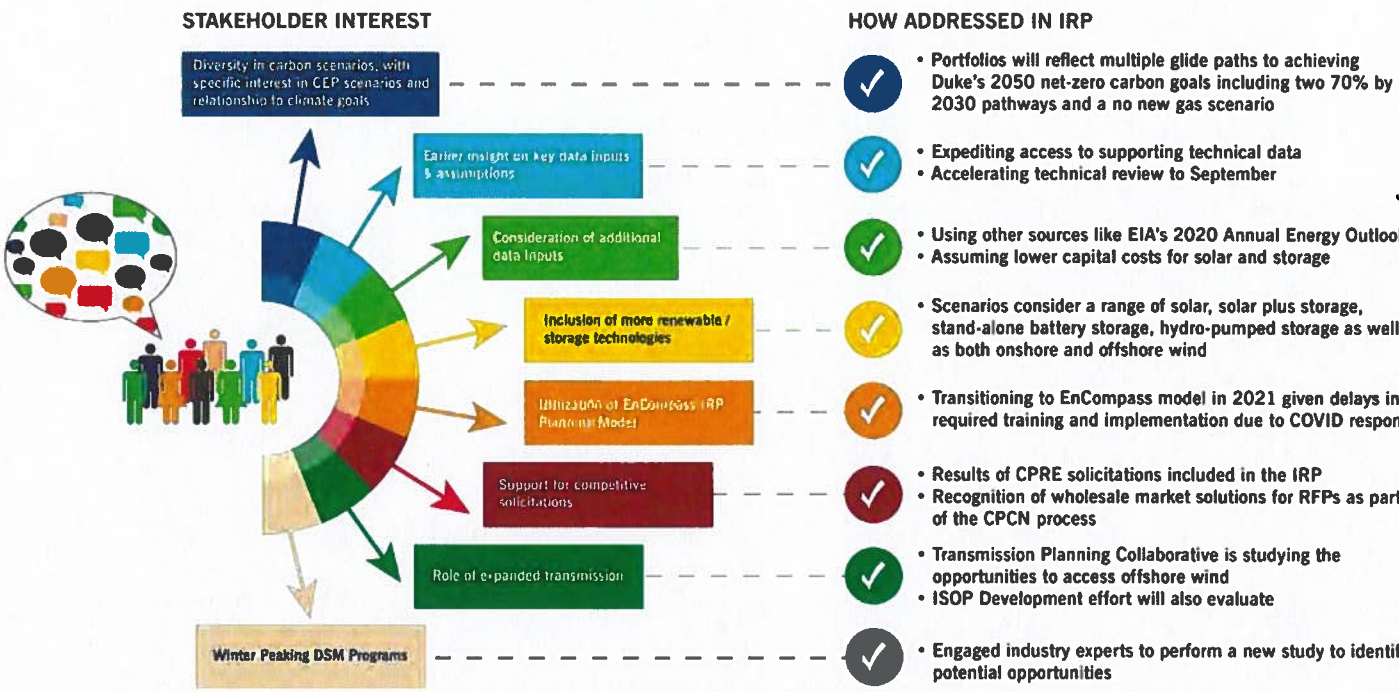
STAKEHOLDER ENGAGEMENT

As part of the development of the 2020 IRP, Duke Energy actively engaged stakeholders in North Carolina and South Carolina with the objectives of listening, educating and soliciting input to inform the planning process. The Company initiated this engagement with local listening sessions followed by a series of virtual events which were facilitated by ICF,[6] and consisted of an IRP 101 education session and three stakeholder virtual forums, with over 200 participants from stakeholder groups involved across all activities. The forums included presentations and discussions from Duke Energy subject matter experts, and enabled discussion around the areas of greatest interest to stakeholders as identified through listening sessions, and pre- and post-engagement surveys. The sessions drew unique external stakeholder participants from across the Carolinas and provided recommendations in the areas of resource planning, carbon reduction, energy efficiency and demand response. Input from stakeholders helped shape the IRP development, and influenced the evaluation of different pathways

[5] Source: MJ Bradley, "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States" – July 2020, p. 30.
[6] www.icf.com, ICF, an advisory and professional services company with a specialty in utility sector planning.

Corrected 11.06.2020

in the 2020 IRP. A summary report of these activities was developed by ICF and can be found on Duke Energy's web site.[7].



2020 IRP INFORMED BY NEW STUDIES, ILLUSTRATES MULTIPLE PATHWAYS

The 2020 IRP is informed by several new studies and analysis as well as collaboration and input from stakeholders. The analysis and studies in this IRP explore the opportunities and challenges over a range of options for achieving varying trajectories of carbon emission reduction. Specifically, the 2020 IRP highlights six possible portfolios, or plans, within the 15-year planning horizon. These portfolios explore the most economic and earliest practicable paths for coal retirement; acceleration of renewable technologies including solar, onshore and offshore wind; greater integration of battery and pumped-hydro energy storage; expanded energy efficiency and demand response and deployment of new zero-emitting load following resources (ZELFRs) such as small modular reactors (SMRs).

Consistent with regulatory requirements, the base case portfolios evaluate the need for the new resources associated with customer growth and the economic retirement of existing generation under

[7] www.duke-energy.com/irp.

Corrected 11.06.2020

a "no-carbon policy" view and a "with carbon policy" view respectively. These base case portfolios employ traditional least cost planning principles as prescribed in both North Carolina and South Carolina. The remaining plans build upon the carbon base case and were constructed with the assumption of future carbon policy. As described below, and in more detail in Appendix A, these six portfolios show different trajectories for carbon reduction with varying inputs such as coal retirement dates, types of resources and the level and pace of technology adoption rates, as well as contributions from energy efficiency and demand-side management initiatives. All six portfolios were evaluated under combinations of differing carbon and gas prices to test the impact these future scenarios would have on each plan. The results of that scenario analysis, including a table with retirement dates for each portfolio, are presented in Appendix A.

The portfolios also incorporate varying levels of demand-side management programs as an offset to future demand and energy growth. Stakeholders have voiced strong support for these initiatives and the Company has responded by including new conservation programs like Integrated Volt-Var Control (IVVC) which will further support the integration of renewables while also delivering peak and energy demand savings and enhanced reliability for our customers over time, and is further described in Appendix D. With input and support from stakeholders, the Company also undertook a new Winter Peak Shaving study with top consultants in this field. While more work is needed to develop and gain approval for new programs and complementary rate designs, this study provides an increased level of confidence that the high energy efficiency and demand response assumptions used in the portfolios with higher carbon reductions (D - F) could be realized with supportive regulatory policies in place.

The following table outlines the supportive studies used in development of this IRP. These studies cover an array of topical areas with perspective and analysis from some of the industry's leading experts in their respective fields.

DUKE ENERGY CAROLINAS

STUDY REQUIREMENTS

STUDY	STUDY REQUIREMENTS
Economic Coal Retirements	• Analysis established the most economic coal unit retirement dates for the Base CO_2 and Base No CO_2 scenarios.
Earliest Practicable Coal Retirements	• Analysis established the earliest feasible coal unit retirement dates. Analysis set aside normal economic considerations and focused on procurement and construction timelines for replacement capacity in order to retire the coal units at the earliest attainable dates.
Resource Adequacy Study/ Reserve Margin Study	• Astrapé Consulting study evaluated reliability based on meeting the one day in ten years loss of load expectation (LOLE) metric.
Storage Effective Load Carrying Capability (ELCC) Study	• Astrapé Consulting study evaluated capacity value of storage under multiple conditions, including its contribution to winter peak and considerations with increasing levels of renewable penetration.
Energy Efficiency and Market Potential Study	• Nexant study evaluated market potential for energy efficiency and demand response initiatives.
Winter Specific DR and Rate Design Benchmarking Study	• Being conducted by Tierra Resource Consultants, Proctor Engineering Group, and Dunsky. Studies the integration of new rate designs and DSM technology with innovative program structures to drive winter peak focused reductions.

GRID INVESTMENTS

Significant investment in the transmission and distribution system will be required to retire existing coal resources that support the grid and to integrate the incremental resources forecasted in this IRP. While grid investments are critical, ascribing precise cost estimates for individual technologies in the context of an IRP is challenging as grid investments depend on the type and location of the resources that are being added to the system. As described in Appendix A, if replacement generation with similar capabilities is not located at the site of the retiring coal facility, transmission investments will generally first be required to accommodate the unit's retirement in order to maintain regional grid stability. Furthermore, a range of additional transmission network upgrades will be required depending on the type and location of the replacement generation coming onto the grid. To that end, since the level of retirements and replacement resources vary by portfolio, separate estimates of

Corrected 11.06.2020

potential required transmission investments are shown and are included in the present value revenue requirements (PVRR) for each of the portfolios. On a combined basis, the transmission investments described further in Chapter 7 have an approximate range of $1 billion in the Base Case portfolios to $9 billion in the No New Gas portfolio. The incremental transmission cost estimates are high level projections and could vary greatly depending on factors such as the precise location of resource additions, specific resource supply and demand characteristics, the amount of new resources being connected at each location, interconnection dependencies, escalation in labor and material costs, changes in interest rates and, potential siting and permitting delays beyond the Company's control. These also do not include the costs of infrastructure upgrades that would be needed on affected third party transmission systems, e.g., other utilities and regional transmission organizations.

With respect to the distribution grid, the Company is working to develop and implement necessary changes to the distribution system to improve resiliency and to allow for dynamic power flows associated with evolving customer trends such as increased penetration of rooftop solar, electric vehicle charging, home battery systems and other innovative customer programs and rate designs. Distribution grid control enhancement investments are foundational across the scenarios in this IRP, improving flexibility to accommodate increasing levels of distribution connected renewable resources while developing a more sustainable and efficient grid. In recognition of the critical role of the transmission and distribution system in an evolving energy landscape, the Company believes it will be critical to modernize the grid as outlined in Chapter 16 and to further develop its Integrated System & Operations Planning (ISOP) framework described in Chapter 15. The Company will use ISOP tools to identify and prioritize future grid investment opportunities that can combine benefits of advanced controls with innovative rate designs and customer programs to minimize total costs across distribution, transmission, and generation.

TECHNOLOGY, POLICY AND OPERATIONAL CONSIDERATIONS

As depicted further below, portfolios that seek quicker paces of carbon reductions have greater dependency on technology development, such as battery storage, small modular reactors and offshore wind generation, which are at varying levels of maturity and commercial availability[8]. As a result, these portfolios will have a greater dependence on technology advancements and projected future cost reductions, thus requiring near-term supportive energy policies at the state or Federal levels. For

[8] Source: Browning, Morgan S., Lenox, Carol S. "Contribution of offshore wind to the power grid: U.S. air quality. implications." *ScienceDirect*, 2020, https://www.sciencedirect.com/science/article/abs/pii/S0306261920309867.

Corrected 11.06.2020

example, future policy may serve to lower the cost of these emerging technologies to consumers through research and development funding or by providing direct tax incentives to these technologies.

As noted above, all portfolios will require additional grid investments in the transmission and distribution systems to integrate the new resources outlined in each of the portfolios. The portfolio analysis includes estimates of system costs, associated average residential monthly bill impact and operational and executional challenges for each portfolio. When considering these portfolios across both utilities, a combined look is presented below, followed by a DEC only view.

The "Dependency on Technology & Policy Advancement" row in the portfolio results table below reflects a qualitative assessment for each respective portfolio. More shading within a circle indicates a higher degree of dependence on future development of the respective technologies, supporting policy and operational protocols. The Base without Carbon Policy case reflects the current state, with little to no dependence on further technology advancements, policy development, and minimal operational risks. Working from left to right across the table, all other portfolios, including the Base with Carbon Policy case requires policy changes relative to the current state. The 70% CO_2 Reduction High Wind case would require supportive policies for expeditious onshore and offshore wind development and associated, necessary transmission build by 2030. The 70% CO_2 Reduction High SMR case was included to illustrate the importance of support for advancing these technologies as part of a balanced plan to achieve net-zero carbon. The No New Gas case includes dependence on all factors listed, as well as a much greater dependence on siting, permitting, interconnection and supply chain for battery storage. For the 70% reduction and No New Gas cases, the unprecedented levels of storage that are required to support significantly higher levels of variable energy resources present increased system risks, given that there is no utility experience for winter peaking utilities in the U.S. or abroad with operational protocols to manage this scale of dependence on short-term energy storage.

DUKE ENERGY CAROLINAS

DEC / DEP COMBINED SYSTEM PORTFOLIO RESULTS TABLE

PORTFOLIO	Base without Carbon Policy (A)		Base with Carbon Policy (B)		Earliest Practicable Coal Retirements (C)		70% CO_2 Reduction: High Wind (D)		70% CO_2 Reduction: High SMR (E)		No New Gas Generation (F)	
System CO_2 Reduction (2030 | 2035)[1]	56%	53%	59%	62%	64%	64%	70%	73%	71%	74%	65%	73%
Present Value Revenue Requirement (PVRR) [$B][2]	$79.8		$82.5		$84.1		$100.5		$95.5		$108.1	
Estimated Transmission Investment Required [$B][3]	$0.9		$1.8		$1.3		$7.5		$3.1		$8.9	
Total Solar [MW][4, 5] by 2035	8,650		12,300		12,400		16,250		16,250		16,400	
Incremental Onshore Wind [MW][4] by 2035	0		750		1,350		2,850		2,850		3,150	
Incremental Offshore Wind [MW][4] by 2035	0		0		0		2,650		250		2,650	
Incremental SMR Capacity [MW][4] by 2035	0		0		0		0		1,350		700	
Incremental Storage [MW][4, 6] by 2035	1,050		2,200		2,200		4,400		4,400		7,400	
Incremental Gas [MW][4] by 2035	9,600		7,350		9,600		6,400		6,100		0	
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][7] by 2035	2,050		2,050		2,050		3,350		3,350		3,350	
Remaining Dual Fuel Coal Capacity [MW][4, 8] by 2035	3,050		3,050		0		0		0		2,200	
Coal Retirements	Most Economic		Most Economic		Earliest Practicable		Earliest Practicable[9]		Earliest Practicable[9]		Most Economic[10]	
Dependency on Technology & Policy Advancement	○		◔		◑		◕		●		●	

[1]Combined DEC/DEP System CO_2 Reductions from 2005 baseline

[2]PVRRs exclude the cost of CO_2 as tax. Including CO_2 costs as tax would increase PVRRs by ~$11-$16B. The PVRRs were presented through 2050 to fairly evaluate the capital cost impact associated with differing service lives

[3]Represents an estimated nominal transmission investment; cost is included in PVRR calculation

[4]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon

[5]Total solar nameplate capacity includes 3,925 MW connected in DEC and DEP combined as of year-end 2020 (projected)

[6]Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro

[7]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

[8]Remaining coal units are capable of co-firing on natural gas, all coal-only units that rely exclusively on coal are retired before 2030

[9]Earliest Practicable retirement dates with delaying one (1) Belews Creek unit and Roxboro 1&2 to EOY 2029 for integration of offshore wind/SMR by 2030

[10]Most Economic retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind by 2030

LEGEND:

- ● Completely dependent
- ◕ Mostly dependent
- ◑ Moderately dependent
- ◔ Slightly dependent
- ○ Not dependent

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

DEC PORTFOLIO RESULTS TABLE

PORTFOLIO	A: Base without Carbon Policy		B: Base with Carbon Policy		C: Earliest Practicable Coal Retirements		D: 70% CO_2 Reduction: High Wind		E: 70% CO_2 Reduction: High SMR		F: No New Gas Generation	
System CO_2 Reduction (2030 | 2035)[1]	56%	53%	59%	62%	64%	64%	70%	73%	71%	74%	65%	73%
Average Monthly Residential Bill Impact for a Household Using 1000kWh (by 2030 | by 2035)[2]	$7	$23	$8	$25	$13	$25	$26	$47	$24	$45	$12	$45
Average Annual Percentage Change in Residential Bills (through 2030 | through 2035)[2]	0.7%	1.3%	0.8%	1.5%	1.3%	1.4%	2.3%	2.5%	2.2%	2.5%	1.1%	2.4%
Present Value Revenue Requirement (PVRR) [$B][3]	$44.4		$46.8		$46.8		$56.1		$53.6		$56.0	
Estimated Transmission Investment Required [$B][4]	$0.6		$1.0		$0.7		$4.3		$2.1		$2.7	
Total Solar [MW][5,6] by 2035	3,700		5,950		5,950		8,450		8,450		8,450	
Incremental Onshore Wind [MW][5] by 2035	0		150		0		1,100		1,100		1,400	
Incremental Offshore Wind [MW][5] by 2035	0		0		0		1,350		150		150	
Incremental SMR Capacity [MW][5] by 2035	0		0		0		0		700		700	
Incremental Storage [MW][5,7] by 2035	350		600		600		2,400		2,400		2,400	
Incremental Gas [MW][5] by 2035	4,300		3,050		5,650		4,300		3,950		0	
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][8] by 2035	1,225		1,225		1,225		1,850		1,850		1,850	
Remaining Dual Fuel Coal Capacity [MW][5,9] by 2035	3,050		3,050		0		0		0		2,200	
Coal Retirements	Most Economic		Most Economic		Earliest Practicable		Earliest Practicable[10]		Earliest Practicable[10]		Most Economic	
Dependency on Technology & Policy Advancement	○		◔		◑		◕		●		●	

[1]Combined DEC/DEP System CO_2 Reductions from 2005 baseline

[2]Represents specific IRP portfolio's incremental costs included in IRP analysis; does not include complete costs for other initiatives that are constant throughout the IRP or that may be pending before state commissions

[3]PVRRs exclude the cost of CO_2 as tax. Including CO_2 costs as tax would increase PVRRs by ~$5-$8B. The PVRRs were presented through 2050 to fairly evaluate the capital cost impact associated with differing service lives

[4]Represents an estimated nominal transmission investment; cost is included in PVRR calculation

[5]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon

[6]Total solar nameplate capacity includes 975 MW connected in DEC as of year-end 2020 (projected)

[7]Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro

[8]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

[9]Remaining coal units are capable of co-firing on natural gas, all coal-only units that rely exclusively on coal are retired before 2030

[10]Earliest Practicable retirement dates with delaying one (1) Belews Creek unit to EOY 2029 for integration of offshore wind/SMR by 2030

LEGEND:

- ● Completely dependent
- ◕ Mostly dependent
- ◑ Moderately dependent
- ◔ Slightly dependent
- ○ Not dependent

Corrected 11.06.2020

CUSTOMER FINANCIAL IMPACTS

The Company is committed to the provision of affordable electricity for the residents, businesses, industries and communities served by DEC across its Carolinas' footprint. For each of the six portfolios analyzed, the IRP shows a high level projected present value of long-term revenue requirements and an average residential monthly bill impact across the Company's combined North and South Carolina service territory. Portfolios that have earlier and more aggressive adoption of technologies that are at earlier stages of development in the U.S., such as offshore wind or SMR generators, demonstrate or produce incrementally larger costs (revenue requirements) and bill impacts, but achieve carbon reductions at a more aggressive pace. While the IRP forecasts potential incremental system revenue requirement and system residential bill impact differences associated with each of the various scenarios analyzed in the IRP, it is recognized that these forecasts will change over time with evolving-market conditions and policy mandates. Seeking the appropriate pace of technology adoption to achieve carbon reduction objectives requires balancing affordability while maintaining a reliable energy supply. The Company is actively engaged in soliciting stakeholder input into the planning process and is participating in the policy conversation to strike the proper balance in achieving progressive carbon reduction goals that align with customer expectations while also maintaining affordable and reliable service. Finally, cost and bill impacts presented are associated with incremental resource retirements, additions, and demand-side activities identified in the IRP and as such do not include potential efficiencies or costs in other parts of the business. Factors such as changing cost of capital, and changes in other costs will also influence future energy costs and will be incorporated in future IRP forecasts as market conditions evolve. Finally, future cost of service allocators and rate design will impact how these costs are spread among the customer classes and, therefore, customer bill impacts.

BASE CASES

The IRP reflects two base cases, each developed with a different assumption on carbon policy. The first case assumes no carbon policy, which is the current state today. Alternatively, the second base case assumes a policy that effectively puts a price on carbon emissions from power generation, with pricing generally in line with various past or current legislative initiatives, to incentivize lower carbon resource selection and dispatch decisions needed to support a trajectory to net-zero CO_2 emissions by 2050. Given the uncertainties associated with how a carbon policy may be designed, the 2020 IRP carbon policy includes a cost adder on carbon emissions in resource selection as well as daily

Corrected 11.06.2020

operations, effectively a "shadow price" on CO_2 emissions. This "shadow price" is a generic proxy that could represent the effects of a carbon tax, price of emissions allowances, or a price signal needed to meet a given clean energy standard. Given the uncertainty of the ultimate form of policy, the cost and rate impacts shown only reflect the cost of the resources that would be required to achieve carbon reduction and not the "shadow price" itself. Customers could bear an additional cost if carbon policy takes the form of a carbon tax.

In accordance with regulatory requirements of both North Carolina and South Carolina, the base cases apply least cost planning principles when determining the optimal mix of resources to meet customer demand. It should be noted that even the Base Case without Carbon Policy includes results that more than double the amount of solar connected to the DEC and DEP system today. In addition, the Base Case without Carbon Policy includes approximately 1,000 MW of battery storage across the two utilities, which is slightly above the total amount in operation in the U.S. today (source: EIA[9]). The inclusion of a price on carbon emissions drives outcomes that include higher integration of solar, wind, and storage resources when compared to the case that excludes a carbon price. Both pathways utilize the most economic coal retirement date assumption, rather than relying on the depreciable lives of the coal assets as was the case in previous IRPs.

In the Company's base cases, across DEC and DEP combined, all units that operate exclusively on coal would be retired by 2030. The only remaining units that would continue to operate would be dual-fuel units with operation primarily on lower carbon natural gas. By 2035, 7,000 MW of coal-units representing 17% of nameplate capacity across the DEC and DEP system would retire, with the only remaining dual-fuel units of Cliffside 6 and Belews Creek 1 &2 operating through the remainder of their economic lives primarily on lower carbon natural gas. Under these base cases, DEP retires all 3,200 MW of coal capacity by 2030 and DEC retires approximately 3,800 MW of coal capacity by 2035. The remaining units can continue to provide valuable generation capacity to meet peak demand, with generation making up approximately less than 5% of the energy served by DEC and DEP combined by 2035.

The Company's investment to allow for use of lower carbon natural gas at certain coal sites provides a benefit to customers by optimizing existing infrastructure. This dual-fuel capability also improves operational flexibility to accommodate renewables by lowering minimum loads and improving ramp rates while also reducing carbon emissions over the remaining life of the assets. These base case

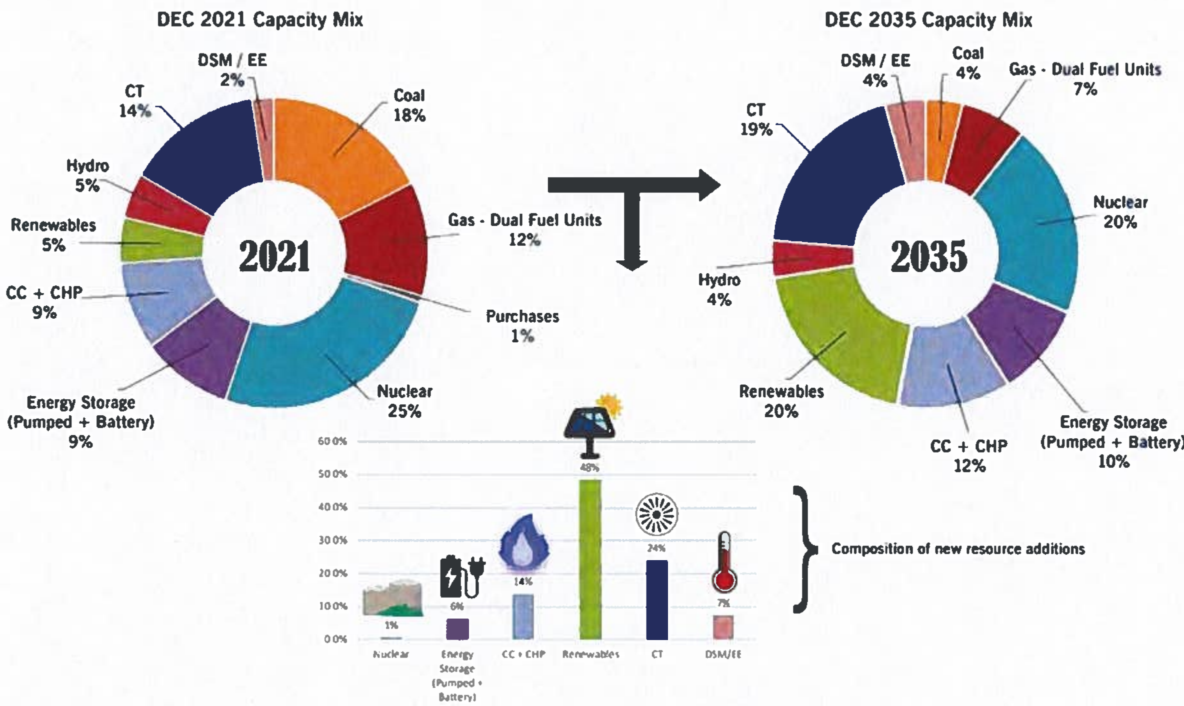
[9] https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

portfolios serve as the benchmark for comparing the incremental costs and benefits of alternative more aggressive carbon reduction scenarios. The figure below illustrates how DEC's capacity mix changes over the 2021 through the 2035 period in the Base Case with carbon policy. For example, renewables make up 48% of the incremental resources added between 2021 and 2035, raising the proportion of renewables in the overall fleet to 20% by 2035.

CHANGE IN INSTALLED CAPACITY[10]



EARLIEST PRACTICABLE COAL RETIREMENTS

For comparison purposes, the Earliest Practicable Retirement case suspends traditional "least cost" economic planning considerations and evaluates the physical feasibility of retiring all the Company's 10,000 MW of coal generation sites within DEC and DEP as early as practicable when taking into consideration the timing required to put replacement resources and supporting infrastructure into

[10] Change in capacity from the Base Case with Carbon Policy portfolio.

Corrected 11.06.2020

service. Aggressive levels of new solar, wind and battery storage were also utilized in this portfolio to accelerate the retirement of a portion of existing coal generation while also reducing the need for incremental gas infrastructure. In determining the "earliest practicable" coal retirement dates, this case considers the siting, permitting, regulatory approval and construction timeline for replacement resources as well as supporting infrastructure such as new transmission and new gas transportation infrastructure. This case assumes the majority of dispatchable resources are replaced at the coal retiring facilities to minimize the resources needed and time associated with additional land acquisition as well as transmission and gas infrastructure that would be required. This approach enables a more rapid transition from coal to lower carbon technologies while maintaining appropriate planning reserves for reliability.

Under this portfolio, all coal units in DEC and DEP would be retired by 2030 with the exception of DEC's Cliffside 6 unit, which would take advantage of its current dual fuel capability and switch to 100% natural gas by 2030. In the aggregate across DEC and DEP, this portfolio includes a diverse mix of over 20,000 MW of new resources being placed in service. This diverse mix results in a combined system carbon reduction of 64% by 2030 while mitigating overall costs and bill impacts by leveraging existing infrastructure associated with the current coal fleet. Finally, while "practicable" from a technical perspective, the sheer magnitude, pace and array of technologies included in this portfolio with approximately half coming from renewable wind and solar resources and half from dispatchable gas, make it evident that new supportive energy policy and regulations would be required to effectuate such a rapid transition.

70% GHG REDUCTION CASES

This IRP also details two cases to achieve a more aggressive carbon reduction goal, such as the goal to achieve 70% greenhouse gas emission reductions from the electric sector by 2030, which is under evaluation in the development of the North Carolina Clean Energy Plan. Achieving these targets will require the addition of diverse, new types of carbon-free resources as well as additional energy storage to replace the significant level of energy and capacity currently supplied by coal units. To support this pace of carbon reduction, this case assumes the same coal unit retirement dates as the "earliest practicable" case, with the exception of shifting the retirement date of one of the Belews Creek units and Roxboro 1&2 units to the end of 2029 to allow for the integration of new carbon free resources by 2030. The resource portfolios in the 70% CO_2 reduction scenarios reflect an accelerated utilization

Corrected 11.06.2020

of technologies that are yet to be commercially demonstrated at scale in the United States and may be challenging to bring into service by the 2030 timeframe.

For the purposes of this IRP, the Company evaluated the emerging carbon free technologies that are furthest along the development and deployment curves – Carolinas offshore wind and small modular nuclear reactors. Adding this level of new carbon free resources prior to 2030 will require the adoption of supportive state policies in both North Carolina and South Carolina. It will also require extensive additional analysis around the siting, permitting, interconnection, system upgrades, supply chain and operational considerations of more significant amounts of intermittent resources and much greater dependence on energy storage on the system. The High SMR case also assumes that SMRs are in service by 2030. However, the challenges with integrating a first of a kind technology in a relatively compressed timeframe are significant. Therefore, these cases are intended to illustrate the importance of advancing such technologies as part of a blended approach that considers a range of carbon-free technologies to allow deeper carbon reductions. When comparing and contrasting the two portfolios, differences in resource characteristics, projected future views on technology costs, associated transmission infrastructure requirements and dependencies on federal regulations and legislation all influence the pace and resource mix that is ultimately adopted in the Carolinas. An examination of two alternate portfolios that achieve 70% carbon reduction by 2030 highlight some of these key considerations for stakeholders. As discussed in Chapter 16, the Company is actively promoting the further development of future carbon free technologies which are a prerequisite to a net-zero future.

NO NEW GAS GENERATION

In response to stakeholder interest in a No New Gas case, the Company evaluated the characteristics of an energy system that excludes the addition of new gas generating units from the future portfolio. coal retirement dates reflected in the base case with the exception of Roxboro 1&2 which are delayed to the end of 2029 to allow for integration of offshore wind by 2030. Similar to the 70% CO_2 reduction cases, this resource portfolio is highly dependent upon the development of diverse, new carbon-free sources and even larger additions of energy storage and offshore wind as well as the adoption of supportive policies at the state and federal level. Also similar to the 70% case, the No New Gas case would require additional analysis around the siting, permitting, interconnection, system upgrades, supply chain integration and operational considerations of bringing on significant amounts of intermittent resources onto the system. Notably, the heavier reliance on large-scale battery energy storage in this scenario would require significant additional analysis and study since this technology

Corrected 11.06.2020

is emergent with very limited history and limited scale of deployment on power grids worldwide. To provide a sense of scale, at the combined system level it would require approximately 1,100 acres of land, or more than 830 football fields to support the amount of batteries in this portfolio and would represent over six times the amount of large-scale battery storage currently in service in the United States. The lack of meaningful industry experience with battery storage resources at this scale presents significant operational considerations that would need to be resolved prior to deployment at such a large scale, which is addressed further in Chapter 16.

Finally, in the combined DEC and DEP view, the No New Gas case is estimated to have the highest customer cost impacts primarily due to the magnitude of early adoption of emerging carbon free technologies and the significant energy storage and transmission investments required to support those technologies. As is the case with almost all technologies, improvements in performance and reductions in cost are projected to occur over time. Without the deployment of new efficient natural gas resources as one component of a long-term decarbonization strategy, the system must run existing coal units longer to allow emerging technologies to evolve from both a technological and an economic perspective. In the alternative, the acceleration of coal retirements without some consideration of new efficient natural gas as a transition resource forces the large-scale adoption of such technologies before they have a chance to mature and decline in price, resulting in higher costs and operational risks for consumers. The summary table highlights the fact that this scenario is dependent on significant technological advances and new policy initiatives that would seek to recognize and address these considerations prior to implementation.

KEY ASSUMPTIONS

The following table provides an overview of the key assumptions applied to our modeling and analysis with comparisons to 2019 IRP. In addition, the company runs a number of sensitivities, such as high and low load growth, energy efficiency and renewable integration levels that demonstrate the impact of changes in various assumptions.

DUKE ENERGY CAROLINAS

KEY ASSUMPTIONS TABLE

TOPIC AREA	2019 IRP	2020 IRP	NOTES
Load Forecast	**DEC:** 0.8% Winter Peak Demand CAGR **DEP:** 0.9% Winter Peak Demand CAGR	**DEC:** 0.6% Winter Peak Demand CAGR **DEP:** 0.9% Winter Peak Demand CAGR	Lower load growth due to economic factors and refinements of historical load data.
Reserve Margin	17%	17%	New LOLE Study reaffirms 17% strikes the appropriate balance between cost and reliability
Solar (Single Axis Tracking)	37% cost decline through 2030	42% cost decline through 2030	7% lower year one cost compared to 2019 IRP
4-hour Battery Storage	54% cost decline through 2030	49% cost decline through 2030	32% lower year one cost compared to 2019 IRP
Onshore Wind	12% cost decline through 2030	11% cost decline through 2030	7% lower year one cost compared to 2019 IRP; For the first time, wind allowed to be economically selected in planning process
Offshore Wind	N/A	40% cost decline through 2030	For the first time, offshore wind is considered in the planning horizon
Natural Gas	17% cost decline through 2030	17% cost decline through 2030	No Material Change
Coal	Retired based on depreciable lives at the time of the IRP	Retired based on analysis for most economic and earliest practicable retirement dates	Scenarios consider earliest practicable and most economic
New Nuclear	SMRs discussed but not screened for selection	SMRs included for selection	For the first time, SMRs available to be economically selected as a resource

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

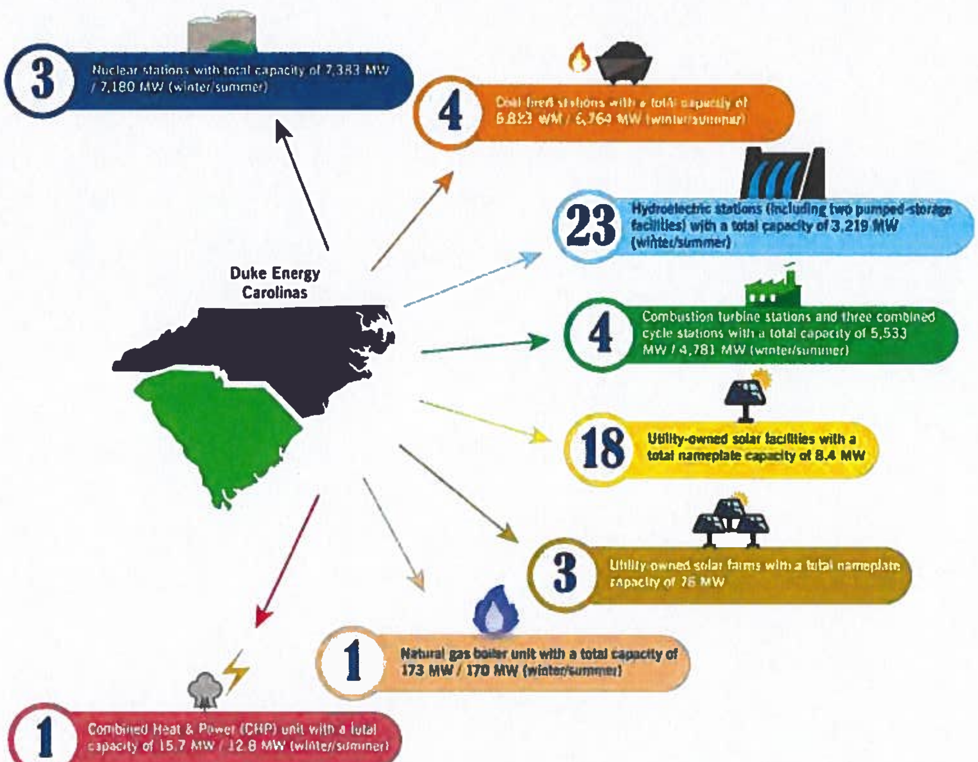
EXECUTIVE SUMMARY CONCLUSION

DEC remains focused on transitioning to a cleaner energy future, advancing climate goals that are important to its customers and stakeholders, while continuing to deliver affordable and reliable service. The 2020 IRP reflects multiple potential future pathways towards these goals. An analysis of each case reflects the associated benefits and costs with each portfolio as well as challenges that would need to be addressed with more aggressive carbon reduction scenarios. This range of portfolios helps illustrate the benefits of a diverse resource mix to assure the reliability of the system and efficiently support the transition toward a carbon-free resource mix. Public policies and the advancement of new, innovative technologies will ultimately shape the pace of the ongoing energy transformation. Duke Energy looks forward to continued engagement and collaboration with stakeholders to chart a path forward that balances affordability, reliability and sustainability.

2 SYSTEM OVERVIEW

DEC provides electric service to an approximately 24,090-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.67 million customers, the Company also sells wholesale electricity to incorporated municipalities and to public and private utilities. Recent historical values for the number of customers and sales of electricity by customer groupings may be found in Appendix C.

DEC currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:



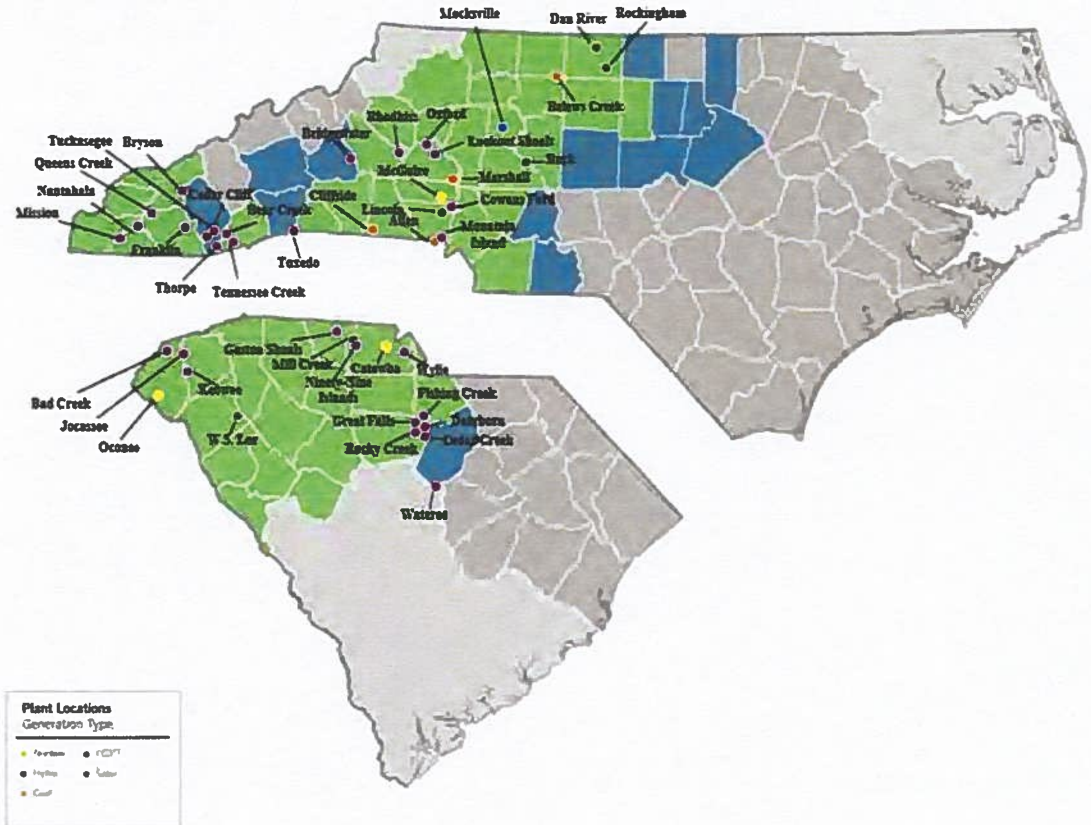
Corrected 11.06.2020

The Company's power delivery system consists of approximately 106,100 miles of distribution lines and 13,068 miles of transmission lines. The transmission system is directly connected to all the Transmission Operators that surround the DEC service territory. There are 35 tie-line circuits connecting with nine different Transmission Operators: DEP, PJM Interconnection, LLC (PJM), Tennessee Valley Authority (TVA), Smokey Mountain Transmission, Southern Company, Cube Hydro, Southeastern Power Administration (SEPA), Dominion Energy South Carolina (DESC) and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) sub-region, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council) and North American Electric Reliability Corporation (NERC).

The map on the following page provides a high-level view of the DEC service area with locations of the electric generation resources.

FIGURE 2-A

DUKE ENERGY CAROLINAS SERVICE AREA

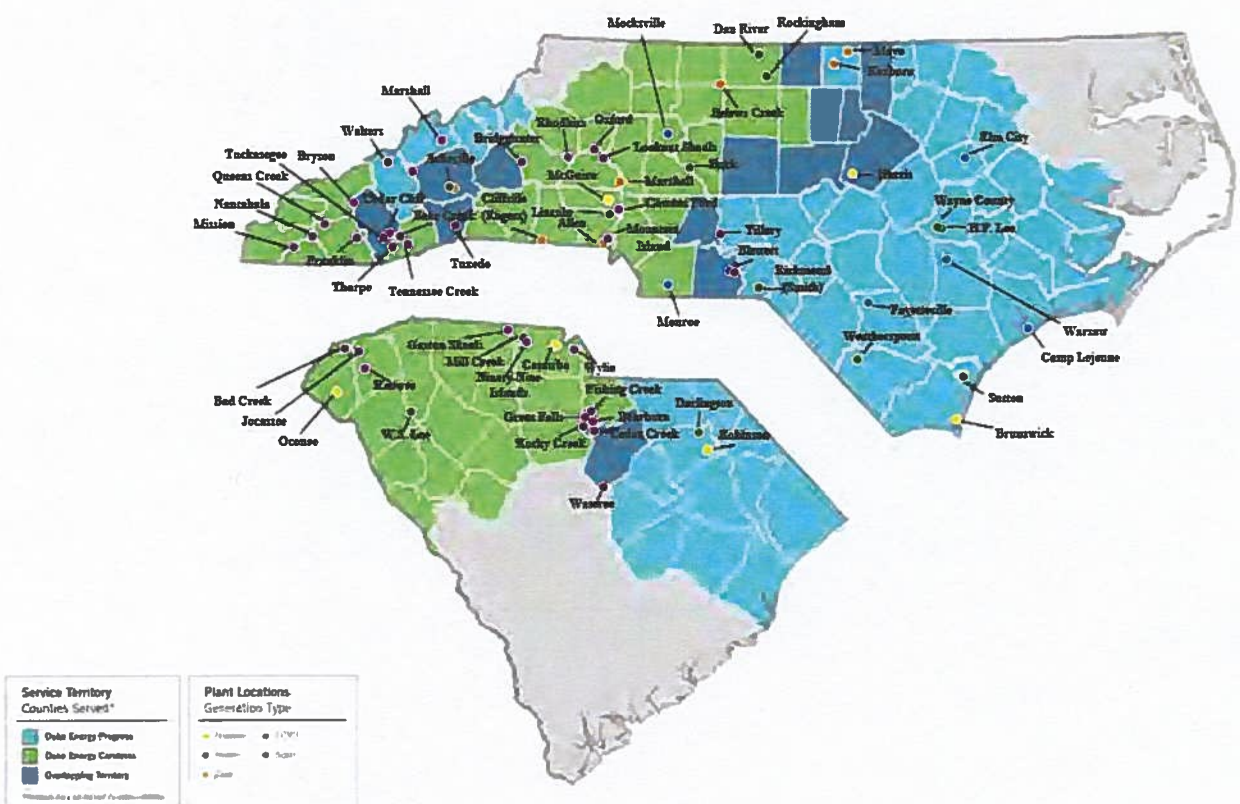


Corrected 11.06.2020

The service territories for both DEC and DEP lend to future opportunities for collaboration and potential sharing of capacity to create additional savings for North Carolina and South Carolina customers of both utilities. An illustration of the service territories of the Companies are shown in the map below.

DUKE ENERGY
CAROLINAS

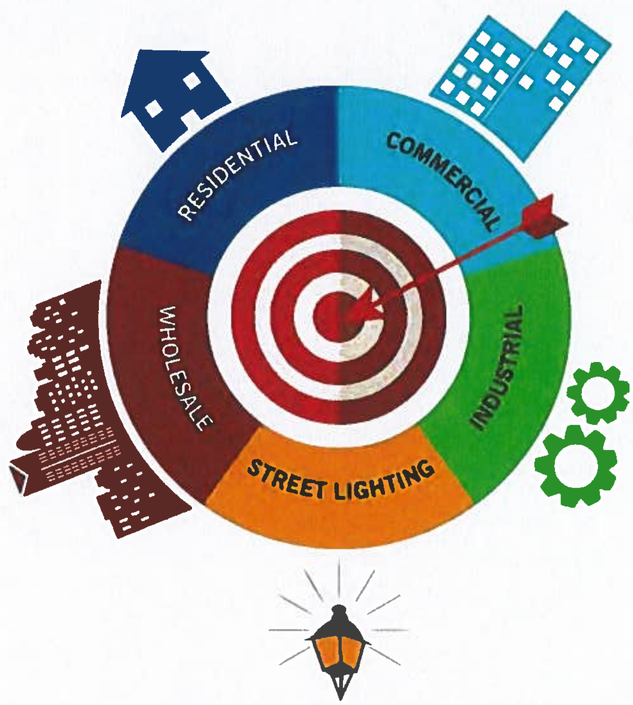
FIGURE 2-B
DEC AND DEP SERVICE AREA



Corrected 11.06.2020

3 ELECTRIC LOAD FORECAST

The Duke Energy Carolinas' Spring 2020 forecast provides projections of the energy and peak demand needs for its service area. The forecast covers the time period of 2021-2035 and represents the needs of the following customer classes:



The Retail forecast consists of the three major classes: Residential, Commercial and Industrial.

The Residential class sales forecast is comprised of two projections. The first is the number of residential customers, which is driven by population. The second is energy usage per customer, which is driven by weather, regional economic and demographic trends, electricity prices and appliance efficiencies. The average annual growth rate of Residential energy sales in the Spring 2020 forecast, including the impacts of Utility Energy Efficiency programs (UEE), rooftop solar and electric vehicles from 2021-2035 is 1.0%.

The three largest sectors in the Commercial class are offices, education and retail. The Commercial forecast also uses an SAE model to reflect naturally occurring as well as government mandated efficiency changes. Commercial energy sales are expected to grow 0.5% per year over the forecast horizon. The Industrial class is forecasted by a standard econometric model, with drivers such as total manufacturing output and the price of electricity. Overall, Industrial sales are expected to decline 0.2% per year over the forecast horizon.

The Company continues to look at ways to improve the load forecasting methodology in order to develop the most accurate and reasonable demand forecasts for DEC. The 2020 load forecast update is lower compared to the 2019 IRP. The decrease in the 2020 update is primarily driven by refinements to peak history, the addition of 2019 peak history and declines in Commercial and Industrial energy sales. The 2020 update also includes revised projections for rooftop solar and electric vehicle programs and the impacts of voltage control programs. The key economic drivers and forecast changes are shown below in Tables 3-A and 3-B. A more detailed discussion of the load forecast can be found in Appendix C.

TABLE 3-A
KEY DRIVERS

	2021-2035
Real Income	2.9%
Manufacturing Industrial Production Index (IPI)	1.1%
Population	1.5%

Table 3-B reflects a comparison between the 2020 and 2019 growth rates of the load forecast with and without impacts of EE.

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

TABLE 3-B

2020 DEC LOAD FORECAST GROWTH RATES VS. 2019 LOAD FORECAST GROWTH RATES (INCLUSIVE OF RETAIL AND WHOLESALE LOAD)

	2020 FORECAST (2021-2035)			2019 FORECAST (2020-2034)		
	Summer Peak Demand	Winter Peak Demand	Energy	Summer Peak Demand	Winter Peak Demand	Energy
Excludes impact of new EE programs	0.9%	0.7%	0.7%	1.2%	1.0%	1.1%
Includes impact of new EE programs	0.8%	0.6%	0.5%	1.0%	0.8%	0.9%

4 ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT AND VOLTAGE OPTIMIZATION

DEC is committed to making sure electricity remains available, reliable and affordable and that it is produced in an environmentally sound manner and, therefore, DEC advocates a balanced solution to meeting future energy needs in the Carolinas. That balance includes a strong commitment to energy efficiency (EE) and demand-side management (DSM).

Since 2009, DEC has been actively developing and implementing new EE and DSM programs throughout its North Carolina and South Carolina service areas to help customers reduce their electricity demands. DEC's EE and DSM plan is designed to be flexible, with programs being evaluated on an ongoing basis so that program refinements and budget adjustments can be made in a timely fashion to maximize benefits and cost-effectiveness. Initiatives are aimed at helping all customer classes and market segments use energy more wisely. The potential for new technologies and new delivery options is also reviewed on an ongoing basis in order to provide customers with access to a comprehensive and current portfolio of programs.

DEC's EE programs encourage customers to save electricity by installing high efficiency measures and/or changing the way they use their existing electrical equipment. DEC evaluates the cost-effectiveness of EE/DSM programs from the perspective of program participants, non-participants, all customers, and total utility spending using the four California Standard Practice tests (i.e., Participant Test, Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test and Utility Cost Test (UCT), respectively) to ensure the programs can be provided at a lower cost than building supply-side alternatives. The use of multiple tests can ensure the development of a reasonable set of programs and indicate the likelihood that customers will participate. DEC will continue to seek approval from

State utility commissions to implement EE and DSM programs that are cost-effective and consistent with DEC's forecasted resource needs over the planning horizon. DEC currently has approval from the North Carolina Utilities Commission (NCUC) and Public Service Commission of South Carolina (PSCSC) to offer a large variety of EE and DSM programs and measures to help reduce electricity consumption across all types of customers and end-uses.

For IRP purposes, these EE-based demand and energy savings are treated as a reduction to the load forecast, which also serves to reduce the associated need to build new supply-side generation, transmission and distribution facilities. DEC also offers a variety of DSM (or demand response) programs that signal customers to reduce electricity use during select peak hours as specified by the Company. The IRP treats these "dispatchable" types of programs as resource options that can be dispatched to meet system capacity needs during periods of peak demand.

In 2019, DEC commissioned an EE market potential study to obtain estimates of the technical, economic and achievable potential for EE savings within the DEC service area. The analysis to develop the market potential study included three distinct scenarios: a Base scenario using the baseline input assumptions, an Enhanced scenario which considered the impact of increased program spending to attract new customers, and an Avoided Energy Cost Sensitivity where higher future energy prices result in increased economic and achievable EE savings potential.

The final report was prepared by Nexant, Inc. and was completed in June 2020. The results of the market potential study are suitable for integrated resource planning purposes and use in long-range system planning models. However, the study did not attempt to closely forecast short-term EE achievements from year to year. Therefore, the EE/DSM savings contained in this IRP were projected by blending DEC's five-year program planning forecast into the long-term achievable potential projections from the market potential study.

DEC prepared a Base EE Portfolio savings projection that was based on DEC's five-year program plan for 2020-2024. For periods beyond 2029, the Base Portfolio assumed that the Company could achieve the annual savings projected in the Base Achievable Portfolio presented in Nexant's Market Potential Study. For the period of 2025 through 2029, the Company employed an interpolation methodology to blend together the projection from DEC's program plan and the Market Potential Study Achievable Potential.

DEC also prepared a High EE Portfolio savings projection based on the Enhanced and Avoided Energy Cost Sensitivity Scenarios contained in Nexant's Market Potential Study. The High EE savings forecast was developed using a similar process to the Base case, however; for the Nexant MPS portion of the forecast, the difference between the Avoided Energy Cost Sensitivity and Base Scenarios for all years was added to the Enhanced Case forecast. This method captures the higher EE savings potential resulting from both the higher avoided energy cost assumptions as well as from increased incentives in the Enhanced case.

Finally, a Low EE Portfolio savings projection was developed by applying a reduction factor to the Base EE Portfolio forecast. Additionally, for the Base, High and Low Portfolios described above, DEC included an assumption that, when the EE measures included in the forecast reach the end of their useful lives, the impacts associated with these measures are removed from the future projected EE impacts. This concept of "rolling off" the impacts from EE programs is explained further in Appendix C.

In addition to the updated MPS and consistent with feedback from stakeholders, the Company undertook a detailed study to specifically examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs that were outside of the MPS scope. To develop this targeted demand response study the Company engaged Tierra Resource Consultants who collaborated with Dunsky Energy Consulting and Proctor Engineering. These firms represent three of the industry's leading practitioners in the development and deployment of innovative energy efficiency and demand response programs across North America. The Company envisions working with stakeholders in the upcoming months and beyond to investigate and deploy, subject to regulatory approval, additional cost-effective programs identified through this effort. At the time of this writing preliminary results from this study show promise for additional winter peak demand savings that could move the Company closer to the high energy efficiency and demand response sensitivity identified in the IRP. While it is premature to include such findings in the Base Case forecast, the results do show a potential pathway for moving closer to the High Case identified in the IRP. Over time as new programs/rate designs are approved and become established, the Company will gain additional insights into customer participation rates and peak savings potential and will reflect such findings in future forecasts.

Lastly, Integrated Voltage/VAR Control (IVVC) is part of the proposed Duke Energy Carolinas Grid Improvement Plan (GIP) and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. If the GIP is

Corrected 11.06.2020

approved for DEC, the rollout of IVVC is anticipated to take approximately four years and will be deployed on 50% of the total circuits and substations across the service territory, accounting for approximately 70% of current base load.

See Appendix D for further detail on DEC's EE, DSM and consumer education programs, which also includes a discussion of the methodology for determining the cost effectiveness of EE and DSM programs. A complete writeup and detailed implementation schedule on the IVVC program is included, as well.

5 RENEWABLE ENERGY STRATEGY / FORECAST

The growth of renewable generation in the United States continued in 2019. According to EIA, in 2019, 9.1 GW of wind and 5.3 GW of utility-scale solar capacity were installed nationwide. The EIA also estimates 3.7 GW of small scale solar was added as well.[1] Notably, U.S. annual energy consumption from renewable sources exceeded coal consumption for the first time since before 1885.[2]

North Carolina ranked sixth in the country in solar capacity added,and first in additions of solar plants greater than 2 MW, in 2019 and remains second behind only California in total solar capacity online, while South Carolina ranked seventh in solar capacity added in 2019.[3] [4] Duke Energy's compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standards (NC REPS), the South Carolina Distributed Energy Resource Program (SC DER or SC Act 236), the Public Utility Regulatory Policies Act (PURPA) as well as the availability of the Federal Investment Tax Credit (ITC) were key factors behind the high investment in solar.

RENEWABLE ENERGY OUTLOOK FOR DUKE ENERGY IN THE CAROLINAS

The future is bright for opportunities for continued renewable energy development in the Carolinas as

[1] All renewable energy GW/MW represent GW/MW-AC (alternating current) unless otherwise noted.
[2] https://www.eia.gov/todayinenergy/detail.php?id=43895.
[3] https://www.seia.org/states-map.
[4] https://www.eia.gov/electricity/data/eia860M/; February month end data

Corrected 11.06.2020

both states have supportive policy frameworks and above average renewable resource availability, particularly for solar. The Carolinas also benefits from substantial local expertise in developing and interconnecting large scale solar projects and the region will benefit from such a concentration of skilled workers. Both states are supporting future renewable energy development via two landmark pieces of legislation, HB 589 in North Carolina (2017) and Act 62 in South Carolina (2019). These provide opportunities for increased renewable energy, particularly for utility customer programs for both large and small customers who want renewable energy. These programs have the potential to add significant renewable capacity that will be additive to the historic reliance on administratively-established standard offer procurement under PURPA in the Carolinas. Furthermore, the Companies' pending request to implement Queue Reform—a transition from a serial study interconnection process to a cluster study process—will create a more efficient and predictable path to interconnection for viable projects, including those that are identified through any current or future procurement structures. It is also worth noting that that there are solar projects that appear to be moving forward with 5-year administratively-established fixed price PURPA contracts and additional solar projects that will likely be completed as part of the transition under Queue Reform.

SUMMARY OF EXPECTED RENEWABLE RESOURCE CAPACITY ADDITIONS

DRIVERS FOR INCREASING RENEWABLES IN DEC

The implementation of NC HB 589, and the passage of SC Act 62 in SC are significant to the amount of solar projected to be operational during the planning horizon. Growing customer demand, the Federal ITC, and declining installed solar costs continue to make solar capacity the Company's primary renewable energy resource in the 2020 IRP. However, achieving the Company's goal of net-zero carbon emissions by 2050 will require a diverse mix of renewable, and other zero-emitting, load following resources. Wind generation, whether onshore wind generated in the Carolinas or wheeled in from other regions of the country, or offshore wind generated off the coast of the Carolinas, may become a viable contributor to the Company's resource mix over the planning horizon.

The following key input assumptions regarding renewable energy were included in the 2020 IRP:

- Through existing legislation such as NC HB589 and opportunities under SC Act 62, along with materialization of existing projects in the distribution and transmission interconnection queues, installed solar capacity increases in DEC from 966 MW in 2021 to 3,493 MW in 2035 with approximately 185 MW of usable AC storage coupled with solar included prior to incremental solar added economically during the planning process.

- Additional solar and solar coupled with storage was available to be selected by the capacity expansion model to provide economic energy and capacity. Consistent with recent trends, total annual solar and solar coupled with storage interconnections were limited to 300 MW per year over the planning horizon in DEC.

- Up to 150 MW of onshore Carolinas wind generation, assumed to be located in the central Carolinas, could be selected by the capacity expansion model annually to provide a diverse source of economic energy and capacity.

- Compliance with NC REPS continues to be met through a combination of solar, other renewables, EE, and Renewable Energy Certificate (REC) purchases.

- Achievement of the SC Act 236 goal of 160 MW of solar capacity located in DEC.

- Implementation of NC HB 589 and SC Act 62 and continuing solar cost declines drive solar capacity growth above and beyond NC REPS requirements.

For more details regarding these assumptions, along with more information about NC HB 589 and SC Act 62, see Appendix E.

BASE WITH CARBON POLICY

The 2020 IRP Base with Carbon Policy case incorporates the projected and economically selected renewable capacities shown below. The projected renewables in this case includes renewable capacity components of the Transition MW, such as capacity required for compliance with NC REPS, PURPA purchases, the SC DER Program, NC Green Source Rider (pre HB 589 program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The Base with Carbon Policy case also includes additional projected solar growth beyond NC HB 589, including potential growth from SC Act 62 and the materialization of additional projects in the transmission and distribution queues. This case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

However, it is the Company's belief that continued declines in the installation cost of solar and storage will enable solar and coupled "solar plus storage" systems to contribute to energy and/or capacity needs. Additionally, the inclusion of a CO_2 emissions tax, or some other carbon emissions reduction policy, would further incentivize expansion of solar resources in the Carolinas. In the Base with Carbon Policy case, the capacity expansion model selected additional solar averaging approximately 100 MW per year beginning in 2025 and solar coupled with storage averaging approximately 120 MW annually beginning in 2028 if a CO_2 tax were implemented in the 2025 timeframe.

In addition to solar generation, wind energy is expected to play an important role in providing a diverse source of generation in the Carolinas. While previous IRPs have contemplated wind generation as a potential resource, for the first time, the 2020 IRP includes wind generation located in the central Carolinas as a technically viable source of carbon free energy and capacity. Though capacity factors of wind generation located in this region are much lower than other onshore or offshore regions, central Carolinas wind benefits from significantly lower transmission costs while still providing a diverse source of carbon free generation. The materialization of wind in the Carolinas is dependent on resolving historic barriers to siting and permitting; but, because the Company views wind as a potentially viable resource and an important step in meeting its carbon reduction goals, central Carolinas wind was included as a resource in the capacity expansion modeling process. With the inclusion of a CO_2 tax beginning in 2025, 150 MW of wind generation was selected annually beginning in the 2034 timeframe.

In addition to onshore wind, the Company is also evaluating offshore wind as a potential energy resource in the short and long term to support increased renewable portfolio diversity, an important resource for achieving the Company's 2050 net-zero carbon emission goal, as well as long-term general compliance need. The 70% CO_2 Reduction: High Wind and No New Gas Generation portfolios both include over 2,400 MW of offshore wind imported into the Carolinas. The challenges with accessing this potential resource are described further in Appendix E.

The Company anticipates a diverse renewable portfolio including solar, biomass, hydro, storage fed by solar, wind and other resources. Actual results could vary substantially for the reasons discussed in Appendix E. The details of the forecasted capacity additions, including both nameplate and contribution to winter and summer peaks are summarized in Table 5-A below.

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

TABLE 5-A

DEC BASE WITH CARBON POLICY TOTAL RENEWABLES

	DEC BASE RENEWABLES - COMPLIANCE + NON-COMPLIANCE														
	MW NAMEPLATE					MW CONTRIBUTION TO SUMMER PEAK					MW CONTRIBUTION TO WINTER PEAK				
	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS / HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL	SOLAR ONLY	SOLAR WITH STORAGE	BIOMASS/ HYDRO	WIND	TOTAL
2021	966	0	132	0	1,099	387	0	132	0	519	10	0	132	0	[illegible]
2022	1,327	115	118	0	1,560	514	70	118	0	702	13	29	118	0	[illegible]
2023	1,673	134	81	0	1,888	636	81	81	0	797	17	34	81	0	[illegible]
2024	1,976	163	81	0	2,219	741	99	81	0	921	20	41	81	0	[illegible]
2025	2,268	192	59	0	2,519	844	116	59	0	1,019	23	48	59	0	[illegible]
2026	2,519	211	49	0	2,778	930	127	49	0	1,106	25	53	49	0	[illegible]
2027	2,708	335	49	0	3,091	977	202	49	0	1,228	27	84	49	0	160
2028	2,895	458	42	0	3,395	1,024	274	42	0	1,340	29	114	42	0	[illegible]
2029	3,082	656	42	0	3,779	1,071	390	42	0	1,502	31	164	42	0	[illegible]
2030	3,217	802	38	0	4,058	1,104	475	38	0	1,618	32	201	38	0	[illegible]
2031	3,352	948	30	0	4,330	1,138	559	30	0	1,727	34	237	30	0	[illegible]
2032	3,486	1,094	12	0	4,592	1,171	642	12	0	1,826	35	273	12	0	[illegible]
2033	3,620	1,238	3	0	4,861	1,205	724	3	0	1,932	36	310	3	0	[illegible]
2034	3,753	1,382	0	0	5,135	1,230	803	0	0	2,032	37	345	0	0	[illegible]
2035	3,885	1,525	0	150	5,560	1,242	875	0	11	2,127	38	381	0	50	[illegible]

Corrected 11.06.2020

As a number of solar contracts are expected to expire over the IRP planning period, the Company is additionally breaking down its solar forecast into three buckets described below:

- **Designated:** Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.

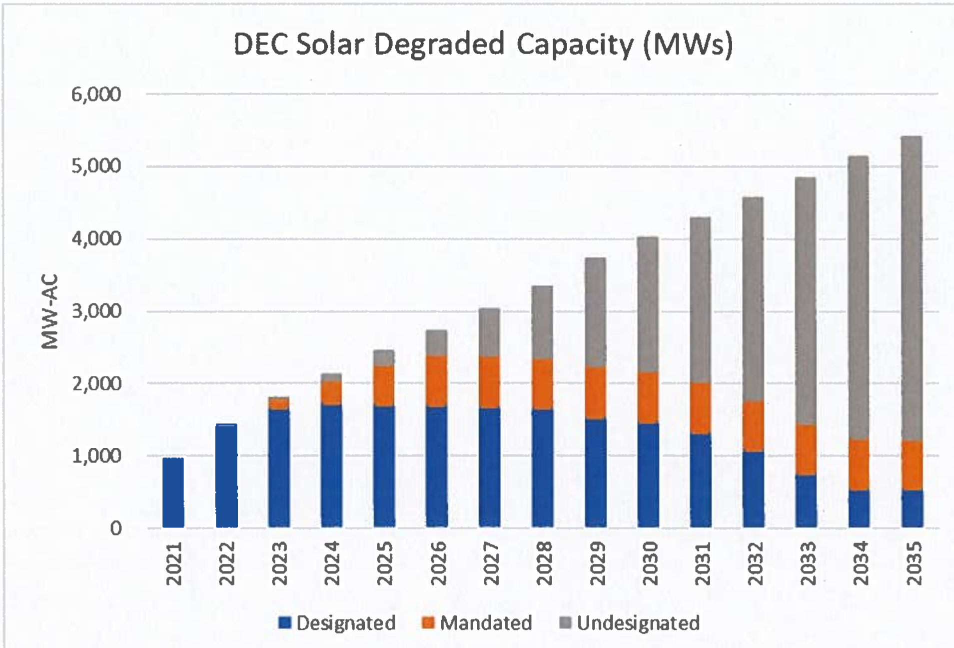
- **Mandated:** Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236).

- **Undesignated:** Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing facilities or new facilities that enter into contracts that have not yet been executed.

The figure below shows DEC's breakdown of these three buckets through the planning period. Note for avoided cost purposes, the Company only includes the Designated and Mandated buckets in the base case.

FIGURE 5-A

DEC SOLAR DEGRADED CAPACITY (MW)



In addition to these base case additions, the Company also developed high and low renewable investment sensitivities that are discussed in Appendix E.

6 ENERGY STORAGE AND ELECTRIC VEHICLES

As part of DEC's broader efforts to modernize the grid, the Company is strategically developing and deploying battery storage projects at locations where it can deliver maximum value for customers and surrounding communities. Battery storage is capable of both storing and dispatching energy at strategic times to provide a variety of benefits for customers as well as the grid. Utility dispatch and operation of battery systems is typically accomplished in fractions of a second, which is critical to manage the continued growth of intermittent resources (e.g. solar and wind) connected to the grid. The versatility of battery storage enables these facilities to be a natural extension of the grid and the Company will continue to apply its engineering and operational expertise to integrate this important technology into its regular planning and grid management functions.

Battery storage costs are declining rapidly which allows the Company to consider the technology as a viable option for grid services, as described in the 2018 IRP, including ancillary services (e.g. frequency regulation, voltage, and ramping support), energy and capacity, renewable smoothing, T&D deferral, and backup power. Operational benefits are gained from improved efficiencies, flexibility, and reliability – in some cases enabling the Company to defer future grid investments that would otherwise be required. The Company is also working with its customers who require enhanced resiliency and energy security as they provide critical services to the community (e.g. hospitals, first responders, emergency shelters and the military).

While there are various types of storage technologies, in the near term, the Company plans to deploy megawatt-scale electrochemical batteries and continues to partner with diverse suppliers who can provide the latest battery technology expertise and resources. The Company is ensuring compliance with evolving regulations and standards related to safety, reliability, and cybersecurity. Furthermore, the Company consults with leading fire protection engineers to guide the design process, includes

Corrected 11.06.2020

multiple layers and levels of safety systems in each of its batteries, and actively engages and trains first responders and 911 reporting centers.

In DEC's 2018 IRP, the Company included 150 MW of nameplate battery storage, representing grid connected projects that have the potential to provide benefits to the generation, transmission, and distribution systems. These 150 MW of nameplate battery storage are also included in this 2020 IRP. Additionally, as discussed in greater detail in Appendix A, the Company sees a growing need for energy storage later in the planning horizon. Meanwhile, DEC continues to analyze other opportunities to utilize battery storage systems, including customer-sited projects and combining battery storage with new or existing PV facilities.

For over a decade, Duke Energy has been piloting emerging battery storage technologies at several sites in the Carolinas. For example, the McAlpine Substation Energy Storage and Microgrid Project in Charlotte, N.C. was commissioned in late 2012. An existing 200-kW BYD lithium iron phosphate battery and a newly installed 30-kW Eos battery is interconnected with a 50-kW solar facility. The batteries provide energy shifting and solar smoothing applications when grid connected and maintain power to a fire station during a grid outage event. At Duke Energy's state-of-the-art research center in Mount Holly, N.C., the Company continues to collaborate with vendors, utilities, research labs and government agencies to develop and commercialize an interoperability framework that enables the integration of distributed resources and demonstrates alternative approaches for microgrid operations.

LONG-TERM OUTLOOK

As solar and other intermittent generation increases on DEC's system, and the cost of battery storage technologies fall, the need for, and value of, additional storage will continue to grow. As shown in Phase 1 of NREL's Integration of Carbon Free Resources Study, storage can play an important role in reducing curtailment of solar resources on DEC's system as the penetration of solar energy expands. However, in DEC, given the availability of 2,140 MW of pumped hydro storage and the projected penetration of renewable energy on the system, battery storage shows less value than Combustion Turbine peaking units in the Base with Carbon Policy portfolio. Importantly, this outcome will be revisited periodically as future projections for battery storage costs evolve. Currently the Company forecasts an approximate 50% decline in battery storage costs by 2030 understanding that the actual pace of technological advancements, or even future potential policy mandates that influence storage costs, may change this forecast in future IRPs.

Corrected 11.06.2020

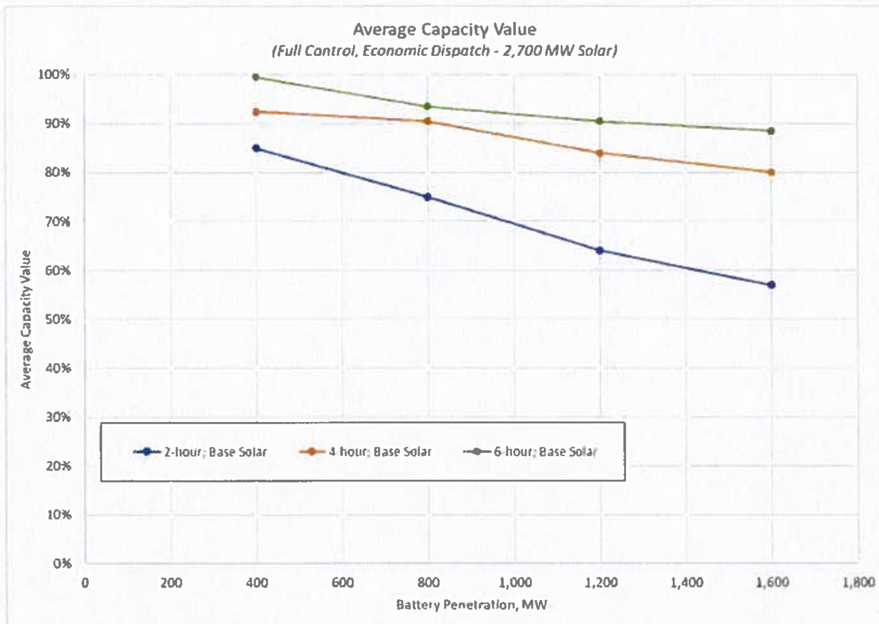
Additionally, the projected steep cost declines of battery storage add some risk to early adoption of this technology. The benefits gained from storage helping to integrate more renewables quicker or potentially replacing retiring generation sooner can likely be captured a few years later at a lower cost to customers. In the Base with Carbon Policy Case, storage coupled with solar is first economically selected in the 2028 timeframe when prices are projected to be more than 40% lower than current estimates.

As is the case with all energy-limited resources, as the penetration of short-term duration storage increases, the incremental benefit of that resource diminishes. To investigate how quickly this loss of value could occur, the Company commissioned Astrapé Consulting, a nationally recognized expert in the field, to conduct a detailed Capacity Value of Battery Storage study that is included as an attachment to the DEC IRP and is discussed in greater detail in Appendix H. This study assessed the contribution to winter peak capacity of varying levels and durations of both standalone battery storage and battery storage paired with solar resources under increasing levels of solar integration. As shown in Figure 6-A, both four and six-hour batteries maintain an average capacity value above 80% to 90% of rated power capacity up to 1,600 MW of penetration on the DEC system. Conversely, the average capacity value of two-hour batteries falls below 80% prior to 800 MW of penetration. This drop is even more dramatic when considering the incremental value of battery storage shown in Figure 6-B. While the first 400 MW of two-hour batteries on the system provide approximately 85% to meeting winter peak capacity needs, the next 400 MW only provide approximately 65%. Two-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hours storage. As the Company seeks to expand winter DSM programs, the value of two-hour storage will likely diminish, and for these reasons, DEC only considered four and six-hour battery storage in the IRP.

Corrected 11.06.2020

FIGURE 6-A

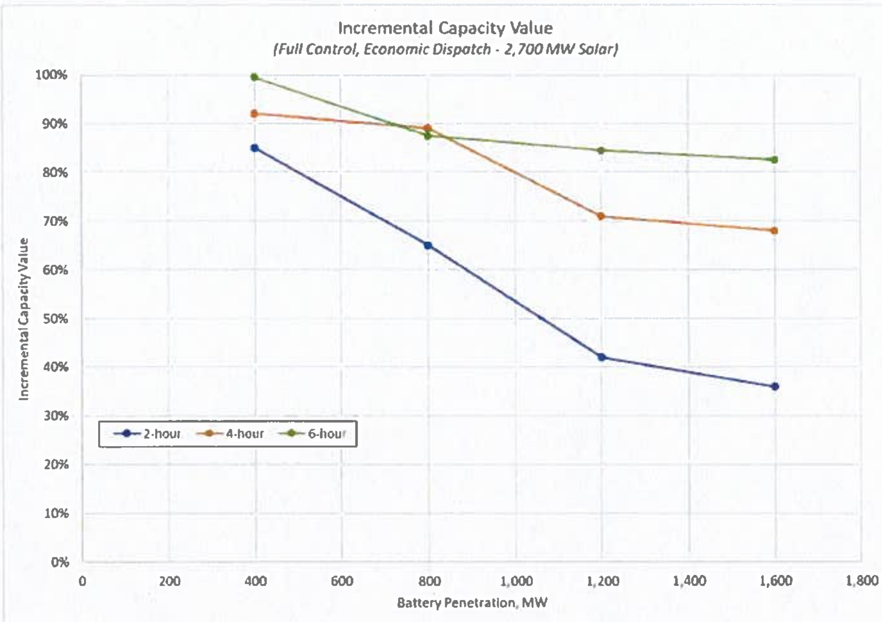
AVERAGE CAPACITY VALUE OF TWO, FOUR, AND SIX HOUR STORAGE



DUKE ENERGY CAROLINAS

FIGURE 6-B

INCREMENTAL CAPACITY VALUE OF TWO, FOUR, AND SIX HOUR STORAGE[1]



The Capacity Value of Storage study also evaluated the capacity value of solar coupled with storage under multiple solar penetrations and with increasing ratios of storage to solar capacity. In this analysis, the battery storage could only be charged from the solar asset it was coupled with, and the solar plus storage maximum output was limited to the capacity of the solar asset. The capacity value of a solar plus storage facility is represented as the percent of solar nameplate capacity, so if a 100 MW solar facility coupled with a 25 MW / 100 MWh battery has a capacity value of 25% the MW contribution to winter peak is 25 MW.

One factor that can impact the capacity value of storage is the level of control the Utility maintains over dispatching the battery. A solar plus storage PURPA QF, may charge and discharge the battery to a fixed, long-term contract with static price signals. Conversely, if the Utility has control over dispatch of the battery, the likelihood that the battery will be available to provide capacity when it is needed is

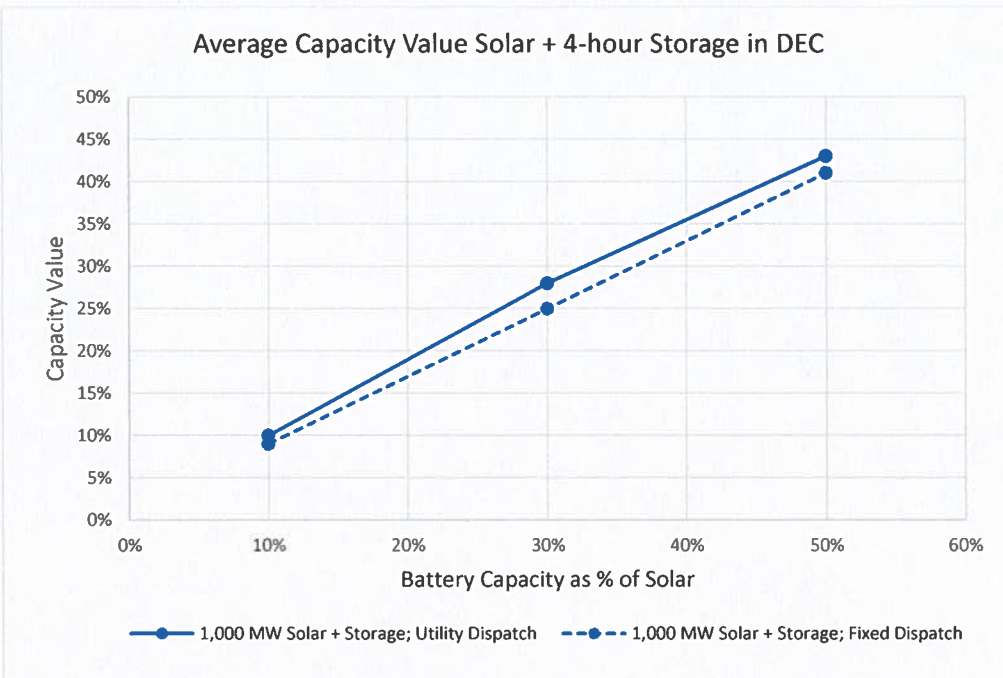
[1] Incremental values are calculated based on the average capacity value for 400 MW increments of battery storage. Due to rounding, calculated incremental values may appear higher or lower than the actual incremental value.

Corrected 11.06.2020

increased. Figure 6-C shows capacity value of the solar plus storage facility can be decreased by 5% to 11% if the storage is dispatched on a fixed price schedule rather than under Utility control.

FIGURE 6-C

AVERAGE CAPACITY VALUE OF SOLAR PLUS STORAGE FACILITY UNDER UTILITY CONTROL VS FIXED DISPATCH SCHEDULE



In addition to the discussion of the Battery ELCC study, Appendix H also includes a discussion of the terminology and operating characteristics of battery storage technologies. There is frequently confusion when discussing the duration, capacity, energy losses, modeling assumptions and costs of battery storage. The "Battery Storage Assumptions" section of Appendix H was developed in order to increase transparency related to Duke's assumptions associated with battery storage in the 2020 IRP.

ELECTRIC VEHICLES

Another important form of energy storage is electric vehicles. Electrification is expected to play an important role in the reduction of carbon dioxide emissions across all sectors of the economy. Electric

Corrected 11.06.2020

vehicles (EVs) in particular are poised to transform and decarbonize the transportation industry which accounts for 28% of US carbon dioxide emissions, more than any other economic sector[2].

EVs also offer financial benefits for consumers and for the electric grid. EV drivers save money on fuel and maintenance costs, and the purchase of a new EV can be offset by up to $7,500 with the Qualified Plug-In Electric Drive Motor Vehicle Tax Credit. Increasing EV growth can create benefits for all utility customers by increasing utilization of the electric grid and putting downward pressure on rates.

Duke Energy receives monthly updates on light-duty vehicle registrations from the Electric Power Research Institute (EPRI). Registrations are tracked by county and attributed to DEC based on the size of its customer count in each county. Reporting and analysis focus on plug-in electric vehicles (PEVs) which are charged from the electric grid. Conventional vehicles and hybrid EVs are also tracked to provide context for PEV growth within the total vehicle market.

According to EPRI 2,700 new PEVs were registered in 2019, and 10,600 PEVs were in operation by the end of the year. Most of those vehicles were adopted in NC which had 9,100 PEVs in operation compared to 1,600 in SC. Annual registrations increased from 2018 to 2019 by a small margin. The modest growth was partly due to an outsized increase in 2018 (+130%) driven by the popular Tesla Model 3 sedan.

On October 29, 2018, NC Governor Cooper issued Executive Order 80, in which he directed the State of NC to "strive to accomplish" increasing the number of registered, zero-emission vehicles to at least 80,000 by 2025. In order to adequately respond to state policies like Executive Order 80, and considering the significant pace of EV adoption in its service territories, Duke Energy recognizes that it must prepare for and better understand the electrical needs and impacts of EVs on its systems. As insufficient charging infrastructure is commonly cited as a barrier to EV adoption[3], Duke Energy believes that more investment in EV charging infrastructure will accelerate EV adoption, consistent with the intent of state policies and the fast-developing EV market. To that end, Duke Energy conducted an analysis to demonstrate the potential electric system/customer benefits of increased EV adoption, and the potential for utility-managed charging to enhance those benefits.

[2] U.S. EPA's Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2018
[3] Edison Electric Institute: Accelerating EV Adoption Report (February 2018).
https://www.eei.org/issuesandpolicy/electrictransportation/Documents/Accelerating_EV_Adoption_final_Feb2018.pdf

Duke Energy designed and proposed electric transportation (ET) pilots in NC and SC to determine best practices for realizing the significant potential benefits of increased ET adoption, including the long-term potential for downward rate pressure, retaining fuel cost savings in the states, reducing vehicle emissions and improving air quality. The ET pilots would span three years and comprise a series of programs that address three areas of concern: EV charging management on the grid, transit electrification and public charging expansion. For EV charging management, Duke Energy proposed a residential EV charging infrastructure rebate and a fleet EV charging infrastructure rebate. For transit electrification, Duke Energy proposed an EV school bus charging program and an EV transit bus charging program for both North and South Carolina, including a Vehicle-to-Grid research component for the EV school bus program. For public charging expansion, Duke Energy proposed a multi-family dwelling charging station program, a public level 2 charging station program and a direct current fast charging station program to establish a baseline network of charging infrastructure across the states.

TABLE 6-A

PROPOSED CAROLINAS ELECTRIC TRANSPORTATION PILOT PROGRAMS

PROGRAM COMPONENT	UNITS (NORTH CAROLINA)	UNITS (SOUTH CAROLINA)
Residential Charging	800	400
Fleet Charging	900	NA
Transit Bus Charging	105	30
School Bus Charging	85	15
Public Level 2/Multi-Family	480	NA
Public DC Fast Charging	120	60

Duke Energy is also partnering with EPRI to study the market potential for non-road EVs and to develop strategies to promote electrification in the commercial and industrial sectors. Commercial and non-road EVs are expected to have a significant impact on the electric grid due to their high utilization rates and high energy demand. Deployment of these technologies, and their impact on the grid, may scale up quickly when companies with large commercial and non-road vehicle fleets transition to EVs. One early example is Amazon's order of 100,000 electric delivery vans from Rivian, expected to be deployed over 2021-2030.

7 GRID REQUIREMENTS

The purpose of this chapter is to describe the development of initial estimates for costs associated with the retirement of coal generating units and siting of replacement generation for the six key portfolios outlined in the Executive Summary and Appendix A.

Retiring existing coal facilities that support the grid and integrating incremental resources forecasted in this IRP will require significant investment in the transmission and distribution systems. As described in Chapter 11 and Appendix A, if replacement generation that can provide similar ancillary service as well as real power needs is not located at the site of the retiring coal facility, transmission investments will generally be required to accommodate the unit's retirement in order to maintain regional grid stability. Furthermore, a range of additional transmission network upgrades will be required depending on the type and location of the replacement generation coming onto the grid. To avoid overstating these Grid upgrade costs, the Company took the approach of assuming resources would be interconnected at the transmission level. In general, connecting generators at the transmission level does not require distribution upgrades, whereas connecting generators at the distribution level can require upgrades to transmission.

With respect to the distribution grid, the Company is working with policy makers and stakeholders to develop and implement necessary changes to the distribution system to improve resiliency and to allow for dynamic power flows associated with evolving customer trends such as increased penetration of rooftop solar, electric vehicle charging, home battery systems and other innovative customer programs. Distribution investments that enable increased levels of distributed energy resources are foundational across the scenarios in this IRP and provide flexibility to accommodate the dynamic power flows resulting from a changing customer service needs and distributed energy resource landscape. In

Corrected 11.06.2020

recognition of the critical role of the transmission and distribution system in an evolving energy landscape, the Company sees significant value in modernizing the distribution portion of the grid as outlined in Chapter 16 and to further develop its Integrated System Optimization and Planning (ISOP) framework described in Chapter 15.

DEC FUTURE TRANSMISSION PROJECTS REQUIRED TO FACILITATE CARBON REDUCTION TARGETS

The six portfolios presented in this IRP included different assumptions for coal plant retirement dates along with a varying array of demand and supply-side resource requirements to reliably serve load over the planning horizon. The Company conducted high-level assessments to estimate the associated necessary transmission network upgrades for retiring the existing coal facilities and integrating each scenario's requisite incremental resources, including combinations of some or all of the following resources: solar, solar-plus-storage hybrid facilities, stand-alone battery storage, pumped-hydro generation/storage, onshore wind, offshore wind, increased off-system purchases, and dispatchable natural gas facilities. These assessments were conducted at a high level utilizing several reasonable, simplifying assumptions. To the extent possible, the Company used recent interconnection studies as a basis for future costs. Extensive additional study and analysis of the complex interactions regarding future resource planning decisions will be needed over time to better quantify the cost of transmission system upgrades associated with any portfolio.

As noted in Appendix L, location, MW interconnection requested, resource/load characteristics, and prior queued requests, in aggregate can have wide ranging impacts on transmission network upgrades required to approve the interconnection request for a new resource and the associated costs. Also, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor, materials, environmental, siting and permitting costs in future years could be significant. In addition to risks associated with costs, to facilitate meeting necessary deadlines for placing new transmission lines and substations in service, policies and approvals for siting and permitting will need to allow for expediting and streamlining associated processes. The timing and nature of these future projects will also be dependent on any neighboring system upgrades needed.

With the significant volume of interconnection requests in the future indicated by the six portfolios described in this IRP, the proposed clustering process associated with queue reform, if approved, will help from a planning studies perspective. The increase in volume of interconnection requests however, unlike the small volume of interconnection requests for traditional larger size generators, will make studying such requests and assigning necessary upgrades quite complex. The complexity and uncertainty of planning for high volumes of DERs, compared to planning for conventional generation that has known capacity and locations with a planning and construction timeline similar to that of the associated transmission upgrades, is much greater for the following reasons:

- The number of permutations of resource types, locations, timing, capacity within resource scenarios and between scenarios can be significant.
- A large volume of both distribution and transmission connected generation and battery storage resources that are in un-sited locations, are of unknown capacity, and have unspecified and variable production profiles, make modeling these resource scenarios very complex.

Given the long lead times for planning, siting, permitting and construction of new transmission, there is some risk that some of the projects represented in the estimates below could not be completed in time to support the in-service dates contemplated by the more aggressive scenarios (C-F).

The resources required to reliably serve load under each portfolio impacts the Company's existing transmission system. Every portfolio requires upgrades to the Duke Energy transmission system, some substantial, and some would require substantial transmission upgrades to other third parties' transmission systems interconnected to Duke Energy's transmission grid. This section outlines high level assessments of the transmission infrastructure required for each portfolio and the estimated costs of that transmission infracture[1]. This section does not attempt to estimate the projects that would be required on third party transmission systems, nor does the Company estimate these third-party costs.

Importantly, the transmission costs for each portfolio and sensitivity presented in this IRP were not calculated directly in each individual case. For instance, transmission costs associated with retiring coal assets were estimated by evaluating the impact of retiring each plant individually without

[1] The cost estimates provided are high-level and not yet at a Class 5 level. As such, the cost estimates could vary greatly depending upon, among other factors, ultimate corridor and resource location, MW interconnection requested, resource/load characteristics, interconnection queue changes, escalation in construction labor and materials costs, siting and permitting, interest rates, cost of capital, and schedule delays beyond the Company's control. In addition, the actual costs for the associated network upgrades are dependent on escalating labor and materials costs. Based on recent realized cost from implementing transmission projects, the escalation of labor and materials costs in future years could be significant.

Corrected 11.06.2020

replacement on site. These estimates were calculated based on information as was known at the time the analysis was conducted and without regard for any particular portfolio. In this manner, in any portfolio where the coal asset was not replaced on site, the transmission cost associated with that plant retirement was assumed to be the same. Furthermore, any new generation added to, or generation removed from, the DEC system in the analysis may significantly impact these cost estimates and therefore, these costs will need to be re-evaluated at the time the decision to retire these assets is made.

Additionally, the cost of integrating increasing levels of distributed and other resources was based on three portfolios:

- Base with Carbon Policy
- 70% CO_2 Reduction: High Wind
- No New Gas Generation

The transmission cost estimates from these portfolios were used as the basis for calculating the transmission costs in all other portfolios and sensitivities discussed in this document. As an example, if the cost to integrate the first 2,000 MW of solar on the DEC system was $100M based on the Base with Carbon Policy, that same cost was assumed to be the cost for integrating the first 2,000 MW of solar in all portfolios and sensitivities. These three specific portfolios were chosen because they represent a broad range of the types of technologies found in all portfolios.

The following are the transmission cost estimates, in overnight 2020 dollars, that were used as a reference in the development of the PVRR values shown later in Appendix A.

DEC FUTURE TRANSMISSION PROJECTS TO FACILITATE RETIREMENT OF EXISTING DEC COAL FACILITIES

The high-level assessment conducted to determine the transmission network upgrades needed to enable the retirement of the DEC coal facilities without replacing generation on site was estimated to be:

- Marshall 1-4: $200 M
- Belews Creek 1&2: $230 M

Cliffside 5 currently does not require transmission upgrades to enable retirement, and Cliffside 6 was assumed to operate on 100% natural gas and was not evaluated for retirement over the planning horizon. Transmission projects to enable a potential Allen retirement are progressing and are not shown as an expense in the IRP analysis.

DEC FUTURE TRANSMISSION PROJECTS TO FACILITATE THE BASE WITH CARBON POLICY PORTFOLIO

The high-level assessment conducted to determine the transmission network upgrades needed to enable the interconnection of new resources for the Base with Carbon Policy portfolio resulted in an estimate of approximately $560M for DEC transmission network upgrades.

DEC FUTURE TRANSMISSION PROJECTS TO FACILITATE THE 70% CO_2 REDUCTION: HIGH WIND PORTFOLIO

The high-level assessment conducted to determine the transmission network upgrades needed to enable the interconnection of new resources for the 70% CO_2 Reduction: High Wind portfolio resulted in an estimate of approximately $1.7B for DEC transmission network upgrades. Estimates for transmission network upgrades to import offshore wind energy were based on prior North Carolina Transmission Planning Collaborative (NCTPC) assessments. An update of these NCTPC assessments are in progress and may result in materially different network upgrade costs.

DEC FUTURE TRANSMISSION PROJECTS TO FACILITATE THE NO NEW GAS GENERATION PORTFOLIO

The high-level assessment conducted to determine transmission network upgrades needed to enable the interconnection of new resources for the No New Gas Generation portfolio resulted in an estimate of approximately $1.9B for DEC transmission network upgrades. This assessment assumes that SMRs can be selectively located at retired coal plant or other brownfield sites. Other locations requested for interconnection could result in necessary network upgrades and significant increased costs. Additionally, DEP imports approximately 2,400 MW of offshore wind in this portfolio. It is likely that to integrate offshore wind energy into the Carolinas; statewide policies would be required, and the transmission infrastructure costs to move the energy from the coast to load centers could be spread across all customers regardless of their legacy transmission provider.

DUKE ENERGY CAROLINAS

DEC/DEP AREA FUTURE TRANSMISSION PROJECTS TO FACILITATE INCREASED IMPORT CAPABILITY

In addition to the estimates shown above, the Company conducted a high-level evaluation of increasing import capability into the DEC and DEP area transmission systems. Based on prior experience and similar transmission interface projects, it is expected that such third-party transmission costs would be substantial; particularly under scenarios where 5 to 10 GWs of power is imported into the DEC/DEP area transmission systems. Additional analysis would be needed to further refine the transmission projects and costs, however these preliminary assessments indicate that extensive incremental Transmission investment would be required if existing generation were retired and replaced with generation outside of the Company's area transmission systems.

The Company conducted a high-level assessment to identify the number of transmission projects and estimated costs associated with increasing import capability into the DEC/DEP area transmission systems from all neighboring transmission regions as well as from offshore wind. The assessments considered the necessary new construction and upgrades needed to increase import capability by 5GW and 10GW respectively.

The 5GW import scenario would require on the DEC/DEP transmission systems alone:

- four (4) new 500kV lines,
- three (3) new 230kV lines,
- two (2) new 500/230kV substations,
- four (4) 300 MVAR SVCs, and
- several reconductor and lower class voltage upgrades.

The estimated costs for the associated transmission projects is between $4B and $5B.

The 10GW import scenario would require on the DEC/DEP transmission systems alone:

- seven (7) new 500kV lines,
- four (4) new 230kV lines,
- three (3) new 500/230kV substations,
- four (4) 300 MVAR SVCs, and
- several reconductor and lower class voltage upgrades.

Corrected 11.06.2020

The estimated costs for the associated transmission projects is between $8B and $10B.

Importantly, actual upgrade costs may vary significantly when the specific projects to enable the requested incremental import capability need are identified through detailed Transmission Planning studies. Equally significant, these estimates exclude the cost of neighboring third-parties' transmission system upgrades, which would be dependent on items, including, but not limited to, the location of the capacity resource being purchased, the MW level of the capacity being purchased, the position in the queue of competing transmission service requests, and the performance of third parties to complete such projects on schedule and on budget.

The system risks with relying on significant incremental import capability for future resource plan needs include, but are not limited to:

a. Delay in resource availability – if required transmission network upgrades on the DEC/DEP transmission system or neighboring transmission systems are delayed due to sitting, permitting, or construction issues, these delays can jeopardize the scheduled in-service date of the transmission upgrades necessary for importing the capacity resource.

b. Loss of local ancillary benefits that are inherent with an on-system resource (e.g. Voltage/Reactive Support, Inertia/Frequency Response, AGC/Regulation for balancing renewable output) may require more on-system transmission upgrades such as adding SVCs for voltage support.

c. Curtailment due to transmission constraints in neighboring areas.

d. Transmission system stability issues under certain scenarios due to added distance between the capacity resource and load.

Corrected 11.06.2020

8 SCREENING OF GENERATION ALTERNATIVES

As previously discussed, the Company develops the load forecast and adjusts for the impacts of EE programs that have been pre-screened for cost-effectiveness. The growth in this adjusted load forecast and associated reserve requirements, along with existing unit retirements or purchased power contract expirations, creates a need for future generation. This need is partially met with DSM resources and the renewable resources required for compliance with NC REPS, HB 589, and SC Act 236. The remainder of the future generation needs can be met with a variety of potential supply side technologies.

For purposes of the 2020 IRP the Company considered a diverse range of technology choices utilizing a variety of different fuels, including Combustion Turbines (CTs), Reciprocating Engines, Combined Cycles (CCs) with and without duct firing, Ultra-Supercritical Pulverized Coal (USCPC) with Carbon Capture and Sequestration (CCS), Integrated Gasification Combined Cycle (IGCC) with CCS, Nuclear, and Combined Heat and Power (CHP). In addition, Duke Energy considered renewable technologies such as Onshore and Offshore Wind, Fixed and Single Axis Tracking (SAT) Solar PV, Landfill Gas, and Wood Bubbling Fluidized Bed (BFB). Duke also considered a variety of storage options such as Pumped Storage Hydro (PSH), Lithium-Ion (Li-Ion) Batteries, Flow Batteries, and Advanced Compressed Air Energy Storage (CAES) in the screening analysis. Lastly, a hybrid of the above technologies was considered: SAT Solar PV with Li-Ion Storage.

For the 2020 IRP screening analysis the Company screened technology types within their own respective general categories of baseload, peaking/intermediate, renewable, and storage with the goal of screening to pass the best alternatives from each of these four categories to the integration process. As in past years the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation on the DEC system. This initial screening evaluation is necessary to narrow down options to be further evaluated in the quantitative analysis process as discussed in Appendix A.

The results of these screening processes determine a smaller, more manageable subset of technologies for detailed analysis in the expansion planning model. Table 8-A details the technologies that were evaluated in the screening analysis phase of the IRP process. The technical and economic screening is discussed in detail in Appendix G.

TABLE 8-A

TECHNOLOGIES SELECTED FOR ECONOMIC SCREENING

DISPATCHABLE (WINTER RATINGS)			
BASELOAD	PEAKING / INTERMEDIATE	STORAGE	RENEWABLE
601 MW, 1x1x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	18 MW, 2 x Reciprocating Engine Plant	10 MW / 10 MWh Lithium-ion Battery	75 MW Wood Bubbling Fluidized Bed (BFB, biomass)
1,224 MW, 2x2x1 Advanced Combined Cycle (No Inlet Chiller and Fired)	15 MW Industrial Frame Combustion Turbine (CT)	10 MW / 20 MWh Lithium-ion Battery	5 MW Landfill Gas
782 MW Ultra-Supercritical Pulverized Coal with CCS	192 MW, 4 x LM6000 Combustion Turbines (CTs)	10 MW / 40 MWh Lithium-ion Battery	NON-DISPATCHABLE (NAMEPLATE)
557 MW, 2x1 IGCC with CCS	201 MW, 12 x Reciprocating Engine Plant	50 MW / 200 MWh Lithium-ion Battery	150 MW Onshore Wind
720 MW, 12 Small Modular Reactor Nuclear Units (NuScale)	752 MW, 2 x J-Class Combustion Turbines (CTs)	50 MW / 300 MWh Lithium-ion Battery	600 MW Offshore Wind
2,234 MW, 2 Nuclear Units (AP1000)	913 MW, 4 x 7FA.05 Combustion Turbines (CTs)	20 MW / 160 MWh Redox Flow Battery	75 MW Fixed-Tilt (FT) Solar PV
9 MW Combined Heat & Power (Reciprocating Engine)		250 MW / 4,000 MWh Advanced Compressed Air Energy Storage	75 MW Single Axis Tracking (SAT) Solar PV
21 MW – Combined Heat & Power (Combustion Turbine)		1,400 MW Pumped Storage Hydro (PSH)	75 MW SAT Solar PV plus 20 MW / 80 MWh Lithium-ion Battery

Corrected 11.06.2020

9 RESOURCE ADEQUACY

Resource adequacy means having sufficient resources available to reliably serve electric demand especially during extreme conditions.[1] Adequate reserve capacity must be available to account for unplanned outages of generating equipment, economic load forecast uncertainty and higher than projected demand due to weather extremes. The Company utilizes a reserve margin target in its IRP process to ensure resource adequacy. Reserve margin is defined as total resources[2] minus peak demand, divided by peak demand. The reserve margin target is established based on probabilistic reliability assessments.

2020 RESOURCE ADEQUACY STUDY

DEC and DEP retained Astrapé Consulting to conduct new resource adequacy studies to support the Companies' 2020 IRPs.[3] The Companies utilized a stakeholder engagement process which included participation from the NC Public Staff, SC Office of Regulatory Staff and the NC Attorney General's Office. The Companies hosted an in-person meeting on February 21, 2020 to provide an overview of the study methodology and model, and to review input data. The Companies worked with stakeholders to define Base Case assumptions and develop a list of planned sensitivities. The

[1] NERC RAPA Definition of "Adequacy" - The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components.
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf, at 9.

[2] Total resources reflect contribution to peak values for intermittent resources such as solar and energy limited resources such as batteries.

[3] Astrapé Consulting is an energy consulting firm with expertise in resource adequacy and integrated resource planning. Astrapé also conducted resource adequacy studies for DEC and DEP in 2012 and 2016.

Companies and Astrapé presented preliminary results to stakeholders on May 8, 2020 and presented recommended reserve margin targets on May 27, 2020.

Astrapé analyzed the optimal planning reserve margin based on (i) providing an acceptable level of physical reliability and (ii) analyzing economic costs to customers at various reserve levels. The most common physical reliability metric used in the industry is to target a reserve margin that satisfies the one day in 10 years Loss of Load Expectation (0.1 LOLE) standard.[4] This standard is interpreted as one firm load shed event every 10 years due to a shortage of generating capacity. The Company and Astrapé believe that physical reliability metrics should be used for determining the planning reserve margin since customers expect a reliable power supply during extreme hot summer conditions and extreme cold winter weather conditions.

Customer costs provide additional information in resource adequacy studies. From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. Similarly, as planning reserve margin decreases, the cost of reserves decreases while the probability of reliability events increases along with an increase in the cost of energy. Thus, there is an economic optimum point where the total system costs (total energy costs plus the cost of unserved energy plus the capacity cost of incremental reserves) are minimized.

All inputs were updated in the new study. Current solar projections increased compared to the 2016 study which shifted more LOLE from summer to winter. As in the 2016 study, winter load volatility remains a significant driver of the reserve margin requirement. In response to stakeholder feedback, the 4-year ahead economic load forecast error (LFE) was diminished by providing a higher probability weighting on over-forecasting scenarios relative to under-forecasting scenarios. As discussed more fully below, this assumption essentially removed any economic load forecast uncertainty from the modeling and put downward pressure on the reserve margin target. Please reference the 2020 Resource Adequacy Study report included as Attachment III for further details regarding inputs and assumptions. Results of the study are presented below.

[4] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf; Reference Table 14 in Appendix A, at A-1. PJM, MISO, NYISO, ISO-NE, Quebec, IESO, FRCC, APS, and NV Energy all use the 1 day in 10-year LOLE standard. As of this report, it is Astrapé's understanding that Southern Company has shifted to the greater of the economic reserve margin or the 0.1 LOLE standard.

DUKE ENERGY CAROLINAS

ISLAND CASE

Astrapé ran an Island Case to determine the level of reserves that would be needed assuming no market assistance is available from neighbor utilities. Results showed that the Company would need to carry a 22.5% reserve margin in the Island Case to satisfy a 0.1 LOLE without neighbor assistance.

BASE CASE

Base Case results reflect the reliability benefits of the interconnected system including the diversity in load and generator outages across the region. Base case results for DEC showed that a 16.0% reserve margin is needed to maintain a 0.1 LOLE. Comparing Base Case results (16.0% reserve margin) to the Island Case (22.5% reserve margin) highlights the significant benefit of being interconnected to neighboring electric systems in the southeast. However, as discussed in more detail in the study report, there are limits and risks associated with too much dependence on neighboring systems during peak demand periods. Careful consideration of the appropriate reliance on neighboring systems is a key consideration in the determination of an appropriate planning reserve margin.

From an economic perspective, Astrapé analyzed total system costs across a range of reserve margins which resulted in a weighted average economic risk neutral reserve margin of 15.0%. The risk neutral level of reserves represents the weighted average results of all iterations at each reserve margin level. However, there are high risk scenarios within the risk neutral result that could cause customer rates to be volatile from year to year. This volatility can be diminished by carrying a higher level of reserves. The study showed that the 90th percentile cost curve resulted in a reserve margin of 16.75%. Please reference the economic reliability results presented in the Executive Summary of the study report for further details regarding the potential capital costs and energy savings at different reserve margin levels.

Base Case results for DEP showed that a 19.25% reserve margin is needed to meet a 0.1 LOLE. The higher physical reserve margin for DEP compared to DEC is driven primarily by greater winter load volatility, and to a lesser extent less import capability. The weighted average risk neutral economic results for DEP yielded a reserve margin of 10.25%[5] and the 90th percentile cost curve resulted in a reserve margin of 17.5%.

[5] Given the significant level of solar on the DEP system, summer reserve margins are approximately 12% greater than winter reserve margins. Thus, the risk neutral reserve margin of 10.25% for DEP is significantly lower than the 19.25%

Corrected 11.06.2020

COMBINED CASE RESULTS

Astrapé also simulated a Combined Case to approximate the reliability benefits of operating the DEC and DEP generation systems as a single balancing authority. This scenario allowed preferential reliability support between DEC and DEP to share capacity, operating reserves and demand response capability. The Combined Case results showed that a 16.75% reserve margin is needed to meet the 0.1 LOLE. The weighted average risk neutral economic results for the Combined Case yielded a reserve margin of 17.0% and the 90th percentile confidence level scenario resulted in a reserve margin of 17.75%.

SENSITIVITIES

A range of sensitivities was simulated in the study to understand which assumptions and inputs impact study results and to address questions and requests from stakeholders. Sensitivities included both physical and economic drivers of reserve margin. Please reference the study report for a detailed explanation of each sensitivity and the reliability and economic results.

TARGET RESERVE MARGIN

Based on the physical and economic reliability results of the Island Case, Base Case, Combined Case, and all sensitivities for both DEC and DEP, Astrapé recommends that DEC and DEP continue to maintain a minimum 17% reserve margin for IRP planning purposes. The Company supports this recommendation and further notes that the results of the Combined Case physical LOLE reserve margin (16.75%), weighted average risk neutral economic reserve margin (17.0%) and 90th percentile economic reserve margin (17.75%) converge on a reserve margin of approximately 17.0%.[6]

As discussed more fully below, the sensitivity results that remove all economic load forecast uncertainty actually increase the reserve margin required to meet 0.1 LOLE. Thus, Astrapé and the Company

reserve margin required to meet 0.1 LOLE since there is little economic benefit of additional reserves in the summer and the majority of the savings seen in adding additional capacity is only being realized in the winter.

[6] In 2019, DEC and DEP entered into an as-available capacity sales agreement which allows the companies to sell excess capacity to the sister utility. This agreement allows the Companies to take advantage of excess capacity available from the sister utility and thus provides some of the enhanced reliability benefits assumed in the Combined Case.

Corrected 11.06.2020

recommend that this minimum target be used in the short- and long-term planning process. A 17% reserve margin provides adequate reliability to customers but also provides rate stabilization by removing the volatility seen in the coldest years, and thus strikes a reasonable balance between reliability and cost. Similar to the 2016 resource adequacy study, Astrapé also recommends maintaining a minimum 15% reserve margin across the summer. Given the resource portfolio in the Base Case, the 15% summer reserve margin will always be met if a 17% winter target is met.

SUPPLEMENTAL INFORMATION

SHORT-TERM VERSUS LONG-TERM RESOURCE PLANNING

The NCUC notes on page 12 of its 2019 IRP order:

> The Commission notes with interest that the Companies appear to acknowledge that it is possible that short-term reserve capacity could fall below the long-term target of 17% without posing a significantly increased risk of resource inadequacy.

This statement is in reference to Duke's response to an NCUC question regarding prior reserve margin targets. Duke stated in its response:[7]

> DEP determined that an 11% capacity margin (12.4% reserve margin) may be acceptable in the near term when there is greater certainty in forecasts; however, a 12%-13% capacity margin (13.6%-14.9% reserve margin) is appropriate in the longer term to compensate for possible load forecasting uncertainty, uncertainty in DSM/EE forecasts, or delays in bringing new capacity additions online.

Astrapé included economic load forecast error in the study to capture the uncertainty in Duke's 4-year ahead load forecast. Four years is the approximate amount of time it takes to permit and construct a new resource. In the 2016 study, the LFE was fit to a normal distribution reflecting equal probably of over-forecasting or under-forecasting load, which resulted in an increase in reserve margin of approximately 1.0-1.5% to account for forecast uncertainty. However, based on stakeholder feedback,

[7] Duke's Responses, Docket No. E-100, Sub 157, at p.19.

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

the 4-year ahead economic LFE in the 2020 study was diminished by using an asymmetric distribution with higher probability weightings on over-forecasting scenarios relative to under-forecasting scenarios. The Company and Astrapé accepted this modeling change in the study; however, it is noted that tailwinds of economic growth such as the adoption rate of electric vehicles and the rate of electrification of end-uses may result in additional load growth uncertainty not captured in the study.

Since there is greater certainty in load in the near term versus longer term, it was anticipated that removal of the LFE uncertainty may support a lower reserve margin in the near term. Interestingly, however, Astrapé ran a sensitivity that removed the LFE uncertainty and results showed a slightly higher reserve margin was required (0.25%) compared to the Base Case. Astrapé ran a second sensitivity that removed the asymmetric Base Case distribution and replaced it with the originally proposed normal distribution. The minimum reserve margin for 0.1 LOLE increased by 1.0% in the Base Case to 17.0%. Since removing the LFE actually increases the reserve margin required to meet the 0.1 LOLE standard (since over-forecasting load is more heavily weighted than under-forecasting load), Astrapé and the Company believe that a 17% minimum reserve margin is appropriate to use for each year of the planning period.

The NCUC also states on page 11 of its 2019 IRP order:

> In terms of risk or volatility, the Commission does not view the differences in Total System Costs are enough to warrant a "hard and fast" minimum reserve margin for planning. This is not to say that the minimum reserve margins supported by the 2016 Astrapé Study are not valid for planning. Rather, the Commission's guidance is that the Companies should not be constrained in their planning to produce resource plans that meet the indicated minimum target reserve margin in each and every one of the plan years.

While the Company supports the general application of a 17% reserve margin target for each year of the planning period, per the NCUC's guidance, the Company will not employ this target as a "hard and fast" constraint in every plan year. Rather, the Company will consider letting reserves decline below 17% in certain circumstances as long as the risk of a loss of load event is not unreasonably compromised. As an example, in the 2020 DEP IRP, reserves were allowed to drop below 17% in 2024 (16.8%) and 2025 (16.6%). At this time, DEP does not plan to make short-term market purchases to satisfy a 17% minimum target; however, DEP will continue to monitor changes in the load forecast and the resource mix and will adjust accordingly.

DUKE ENERGY CAROLINAS

APPROPRIATENESS OF USING THE 0.1 LOLE STANDARD

Customers expect a high level of power reliability, especially during periods of extreme hot or cold weather events. While some power outages may be beyond the Company's control, such as events caused by hurricanes or other natural disasters, customers and regulators expect power to be available during extreme hot and cold periods to power their homes and businesses.[8] As previously noted, the 0.1 standard is widely used across the electric industry and the Company continues to apply the 0.1 LOLE target to determine the level of reserves needed to provide adequate generation reliability. Although this target does not eliminate reliability risk, the Company believes it does provide the level of reliability that customers expect without being overly excessive. The NCUC noted in its 2019 IRP order:[9]

> At this point the Commission is disinclined to direct that in their 2020 IRPs DEC and DEP use some alternative measure of resource inadequacy other than the LOLE .1 standard.

As further support for use of the 0.1 LOLE standard, the Company presents Table 9-A below which shows actual operating reserves during extreme winter weather events for the period 2014-2019. The table shows a total of 13 occurrences when operating reserves declined below 10%, with four occurrences below 5% and three occurrences below 2%. The lowest operating reserve of 0.2% occurred on January 7, 2014. The table also shows the planning reserve margin as projected in the prior year's IRP. For example, on January 7, 2014, actual operating reserves dropped to 0.2% even though the Company's 2013 IRP projected a planning reserve margin of 24.8% based on normal weather for the winter of 2013/2014. The 24.8% projected reserve margin was approximately 8% above the Company's minimum planning target of 17%. It is almost certain DEC would have shed firm load in 2014 had the reserve margin going into the winter been 17%. For the 13 occurrences with operating reserves below 10%, planning reserves ranged from approximately 21% to 28%. Yet, without non-firm market assistance the Company would have shed firm load. This information is also

[8] Section (b)(4)(iv) of NCUC Rule R8-61 (Certificate of Public Convenience and Necessity for Construction of Electric Generation Facilities) requires the utility to provide "... a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located."

[9] NCUC Order Accepting Filing of 2019 Update Reports and Accepting 2019 REPS Compliance Plans, April 6, 2020, at 10.

Corrected 11.06.2020

shown graphically in Figure 9-A below. History has shown that adherence to the 0.1 LOLE standard has provided customers with adequate reliability without carrying an excessive level of planning reserves.

The 0.1 LOLE target is widely used in the industry for resource adequacy planning. The Combined Case economic reserve margin study results presented earlier give similar results to the 0.1 LOLE target of a 17% reserve margin. Further, actual operating reserves history has shown that planning to the 0.1 LOLE standard has provided adequate reliability without having excessive actual reserves at the time of winter peak demands. The Company and Astrapé continue to support use of the 0.1 LOLE for resource adequacy planning.

DUKE ENERGY CAROLINAS

TABLE 9-A
DEC ACTUAL HISTORIC OPERATING RESERVES[10]

RANK (LOWEST TO HIGHEST OPERATING RESERVES)	DATE	PEAK DEMAND (MW)	OPERATING RESERVES* (%)	IRP RESERVE MARGIN** (%)
1	1/7/2014	18,626	0.2	24.8
2	2/20/2015	18,589	1.2	27.6
3	1/8/2015	17,974	1.9	27.6
4	1/30/2014	19,151	2.4	24.8
5	01/02/18	20,890	5.3	21.2
6	01/25/19	16,906	5.9	24.1
7	03/06/19	17,124	6.6	24.1
8	1/24/2014	18,550	7.0	24.8
9	01/31/19	18,875	7.2	24.1
10	2/19/2015	17,427	7.6	27.6
11	01/05/18	21,620	8.0	21.2
12	12/06/18	17,742	9.3	21.2
13	01/11/19	17,705	9.5	24.1

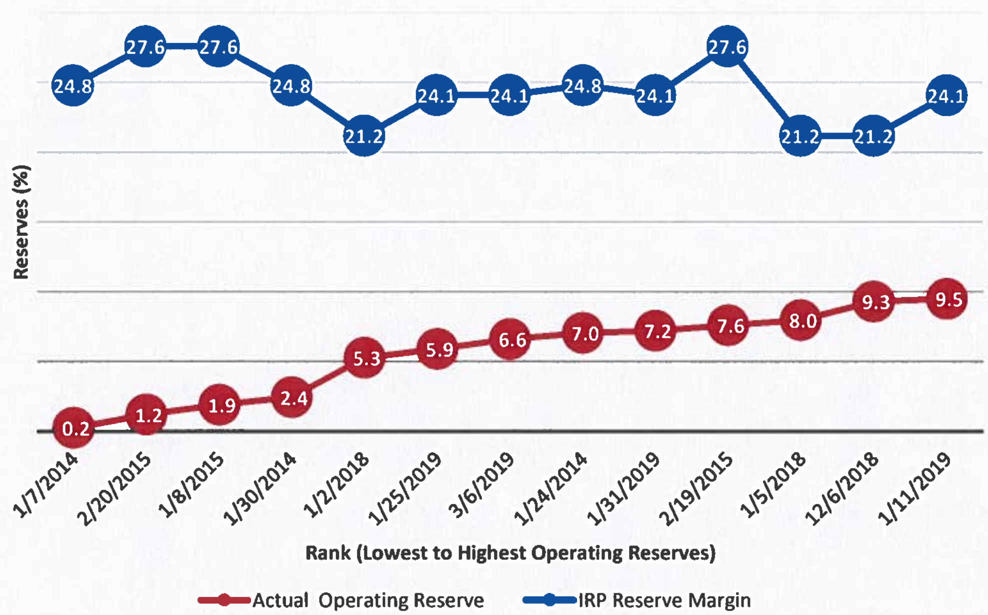
*Operating Reserves represent an estimate based on the last snapshot of projected reserves at the peak for each respective day and include the effects of DR programs that were activated at the time of the peak.

**IRP Reserve Margin reflects the projected reserve margin based on normal weather peak from the previous year's IRP.

[10] The operating reserves shown do not reflect non-firm energy purchases during the hour of the peak system demand in order to ensure a fair comparison with planning reserve margins which also do not include such non-firm purchases that may or may not be available during peak demand hours. The operating reserves data is based on Public Staff data request responses in past IRP dockets.

FIGURE 9-A

DEC ACTUAL HISTORIC OPERATING RESERVES



REGIONAL MODELING

It is important to note that Base Case results reflect the regional benefits of relying on non-firm market capacity resulting from the weather diversity and generator outage diversity across the interconnected system. However, there is risk in over reliance on non-firm market capacity. The Base Case reflects a 6.5% decrease in reserve margin compared to the Island Case (from 22.5% to 16.0%). Thus, approximately 29% (6.5/22.5 = 29%) of the Company's reserve margin requirement is being satisfied by relying on the non-firm capacity market. Astrapé and Duke believe that this market reliance is moderate to aggressive, especially when compared to surrounding entities such as PJM Interconnection L.L.C. (PJM) and the Midcontinent Independent System Operator (MISO). For example, PJM limits market assistance to 3,500 MW which represents approximately 2.3% of its reserve margin, compared

Corrected 11.06.2020

to 6.5% assumed for DEC.[11] Similarly, MISO limits market assistance to 2,331 MW which represents approximately 1.8% of its reserve margin.[12]

As noted in the Executive Summary of the study report, the general trend across the country is a shift away from coal generation with greater reliance on renewable energy resources. As an example, the Dominion Energy (Virginia Electric and Power Company) 2020 IRP shows substantial additions of solar, wind and battery storage to comply with the recent passage of the Virginia Clean Economy Act (VCEA). The excerpt below is from page 6 of the 2020 Dominion IRP:[13]

> In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

Dominion notes its anticipated "need to import a significant amount of energy during the winter" which means Dominion's greater reliance on PJM and other neighbors in the future. Additionally, PJM now considers the DOM Zone to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.[14] The Company also notes California's recent experience with rolling blackouts under extreme weather conditions, as the state continues its shift away from fossil-fuel resources with greater reliance on intermittent renewable resources, storage and imported power.[15]

Duke and Astrapé believe the recommended 17% reserve margin is adequate for near term

[11] https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx - at 1.

[12] https://www.misoenergy.org/api/documents/getbymediaid/80578 - at 24. (copy and paste link in browser)

[13] Dominion Energy (Virginia Electric and Power Company) filed its 2020 IRP as the Astrapé study was underway. Dominion's 2020 IRP can be found at https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509.

[14] Dominion Energy 2020 IRP, at 40.

[15] https://www.greentechmedia.com/articles/read/how-californias-shift-from-natural-gas-to-solar-is-playing-a-role-in-rolling-blackouts.

DUKE ENERGY CAROLINAS

planning and appropriately captures the diversity in load and unit outage events with PJM and other neighbors. The Company used the 17% reserve margin target for the entire 15-year planning period in the IRP. However, changes in resource portfolios of neighboring utilities, as well as the experience in other states to meet extreme weather peak demands with high renewables portfolios, make reliability planning more challenging and place less confidence in future market assistance. For example, today neighboring systems with load diversity may be willing to turn fossil units on early or leave them running longer to assist an adjoining utility during a peak demand period. In the future, with the potential for battery storage to replace a portion of retiring fossil generation, neighboring systems may be reluctant to sell stored energy if they believe that limited stored energy may be required for their native load. Thus, future resource adequacy studies may show less regional benefit of the interconnected system, resulting in the need to carry greater reserves in the longer term. Duke will continue to monitor changes that may impact resource adequacy.

ADEQUACY OF PROJECTED RESERVES

The IRP provides general guidance in the type and timing of resource additions. Projected reserve margins will often be somewhat higher than the minimum target in years immediately following new generation additions since capacity is generally added in large blocks to take advantage of economies of scale. Large resource additions are deemed economic only if they have a lower Present Value Revenue Requirement (PVRR) over the life of the asset as compared to smaller resources that better fit the short-term reserve margin need.

DEC's resource plan reflects winter reserve margins ranging from approximately 17.1% to 25.3%. Reserves projected in DEC's IRP meet the minimum planning reserve margin target and thus satisfy the 0.1 LOLE criterion. Projected reserve margins exceed the minimum 17% winter target by 3% or more in 2021, 2022, 2023 and 2025, primarily as a result of a reduction in the load forecast. The Lincoln CT addition and full deployment of IVVC also contribute to the higher reserves in 2025.

Corrected 11.06.2020

10 NUCLEAR AND SUBSEQUENT LICENSE RENEWAL (SLR)

NUCLEAR ASSUMPTIONS IN THE 2020 IRP

With respect to nuclear generation overall, the Company will continue to monitor and analyze key developments on factors impacting the potential need for, and viability of, future new baseload nuclear generation. Such factors include further developments on the Vogtle project and other new reactor projects worldwide, progress on existing unit relicensing efforts, nuclear technology developments, and changes in fuel prices and carbon policy.

SUBSEQUENT LICENSE RENEWAL (SLR) FOR NUCLEAR POWER PLANTS

DEC and DEP collectively provide approximately one half of all energy served in their NC and SC service territories from clean carbon-free nuclear generation. This highly reliable source of generation provides power around the clock every day of the year. While nuclear unit outages are needed for maintenance and refueling, outages are generally relatively short in duration and are spread across the nuclear fleet in months of lower power demand. In total the fleet has a capacity factor, or utilization rate, of well over 90% with some units achieving 100% annual availability depending on refueling schedules. Nuclear generation is foundational to Duke's commitment to providing affordable, reliable electricity while also reducing the carbon footprint of its resource mix. Currently, all units within the fleet have operating licenses from the Nuclear Regulatory Commission (NRC) that allow the units to run up to 60 years from their original license date.

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

License Renewal is governed by Title 10 of the Code of Federal Regulations (10 CFR) Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants.* The NRC has approved applications to extend licenses to up to 60 years for 94 nuclear units across the country.

SLR would cover a second license renewal period, for a total of as much as 80 years. The NRC has issued regulatory guidance documents, NUREG-2191 [Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report] and NUREG-2192 [Standard Review Plan for the Review of Subsequent License Renewal (SRP-SLR) Applications for Nuclear Power Plants], establishing formal regulatory guidance for SLR.

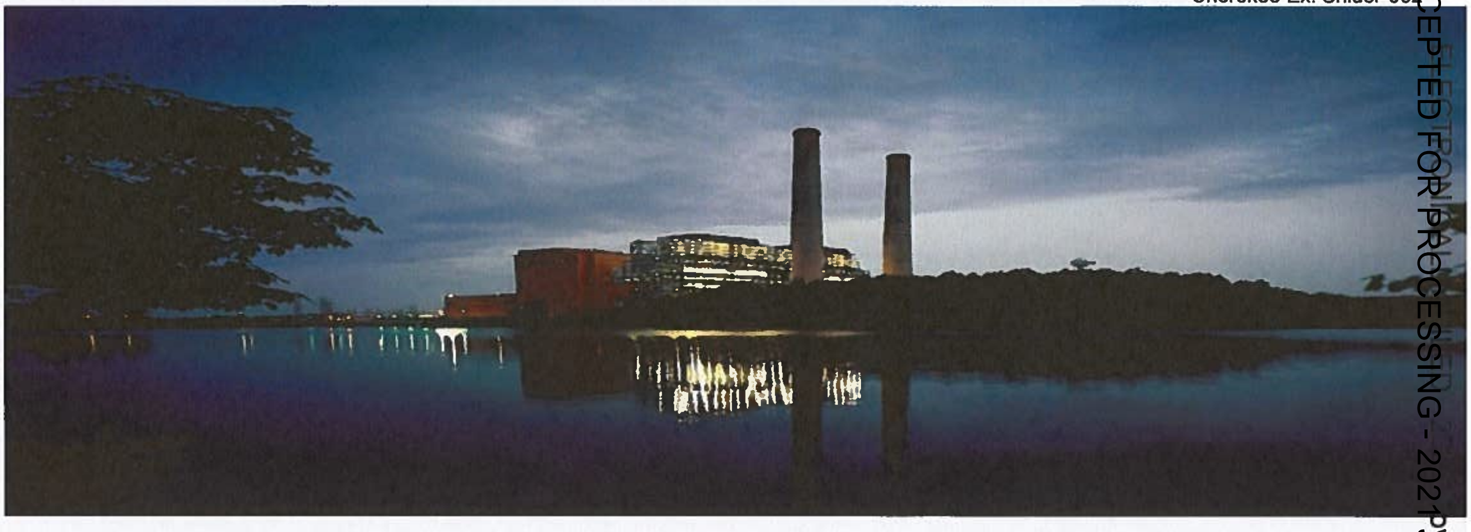
NextEra submitted the industry's first SLR application to the NRC on January 31, 2018 for its Turkey Point station, which became the first nuclear units to receive a second renewed license in December 2019. The NRC review was completed in approximately 18 months from the completion of the sufficiency review.

On July 10, 2018, Exelon Corporation submitted an SLR application for its Peach Bottom plant. The Peach Bottom second renewed license was issued in March 2020, also in approximately 18 months from the completion of the sufficiency review.

Dominion Energy submitted an SLR application for its Surry station on October 15, 2018 and is currently in the final stages of the process of receiving its second renewed license. Dominion Energy plans to submit an SLR application for its North Anna plants in 2020.

Based on the technologically safe and reliable operation of the Duke Energy nuclear fleet, the economic benefits of continued operation of the current nuclear fleet and the environmental role played by the nuclear fleet to continue to reduce carbon emissions, Duke Energy announced in September 2019 its intent to pursue SLR for all eleven nuclear units in the operating fleet. The Oconee SLR application will be submitted first, in 2021. An SLR application takes approximately three years to prepare and approximately two years to be reviewed and approved.

Corrected 11.06.2020



11 COAL RETIREMENT ANALYSIS

For more than 60 years, coal assets in the DEC fleet have provided reliable capacity and energy to DEC's customers. These assets continue to provide year-round energy that is especially critical during winter and summer peaks. However, as the industry landscape changes and market forces drive down costs of other resources, it is important to continue to evaluate the economic benefit the coal fleet provides to customers.

In order to assess the on-going value of these assets, DEC conducted a detailed coal plant retirement analysis to determine the most economic retirement dates for each of the Company's coal assets. This analysis identified the retirement dates used in the Base Cases developed with and without Carbon Policy for each of DEC's coal plants. In addition to the economic retirement analysis, the Company also determined the earliest practicable retirement dates for each coal asset. The "earliest practicable" retirement date portfolio is discussed in Appendix A.

The retirement dates discussed in this chapter do not represent commitments to retire. The IRP is a planning document, but the execution of the plan can vary for multiple reasons including changes to the load forecast, market conditions, and generator performance just to name a few. Similar to new undesignated resources identified in this document that do not have an approval to build or a commitment to build, the coal retirement dates presented herein only represent the current economic retitement dates and are not a commitment to retire.

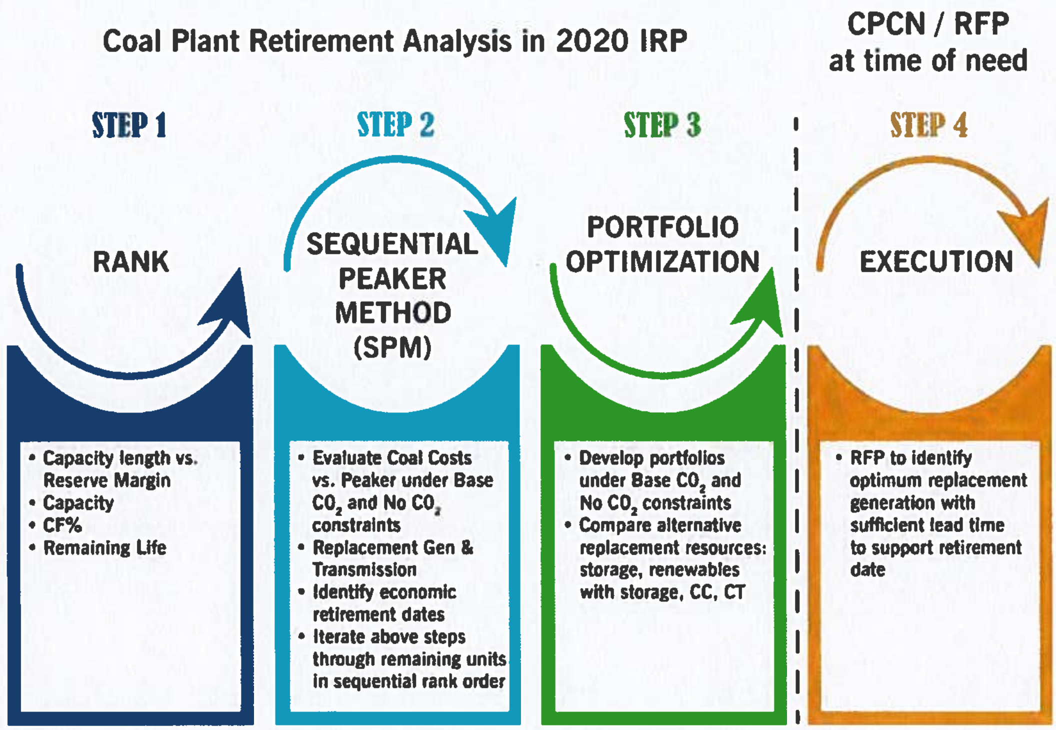
FOUR-STEP PROCESS

The economic retirement dates, along with the optimum replacement generation, of the coal plants were determined through the process depicted in the diagram below.

Corrected 11.06.2020

FIGURE 11-A

PROCESS FOR DETERMINING ECONOMIC RETIREMENT DATES AND REPLACEMENT GENERATION OF COAL PLANTS



The first three steps of the process include both identifying the most economic date and the most economic replacement resources for the retiring coal plants. These steps are included in the 2020 IRP and are detailed in the discussion below. Steps 2 & 3 were evaluated under Base Cases with and without Carbon Policy.

The fourth step in the process, or the execution step, occurs outside of the IRP when the retirement date for the plant is finalized and replacement resource needs are determined. Importantly, the Company includes assumptions for future costs and the commercial availability of replacement resources in the first 3 steps of the retirement analysis, as well as throughout the entirety of the IRP. Only at the time of execution, when the Company issues an RFP for replacement resources, will the *actual* costs, availability, and need for those resources be known.

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

STEP 1: RANKING PLANTS FOR RETIREMENT ANALYSIS

Due to the retirement of one asset impacting the operation and value of other assets on the system, it was important to identify the order in which to conduct the retirement analysis. Additionally, the Joint Dispatch Agreement (JDA) between DEC and DEP allows for non-firm energy purchases and sales between the two utilities. Because of this interaction, the ranking of assets for retirement was evaluated across the utilities, and both DEC and DEP assets are presented below.

To rank the assets for retirement, the Company first ran preliminary capacity expansion plan and production cost models to determine the capacity factors (CF%) for each facility using the 2019 IRP coal plant retirement dates as a starting point for the analysis. This exercise was necessary for estimating future capital and fixed operating and maintenance (FOM) costs at the sites, including incremental coal ash management costs, as well as, for identifying the capacity length versus reserve margin to determine if replacement generation was needed when the individual plants were retired.

The results of Step 1 are shown in Table 11-A below:

TABLE 11-A
RANKING OF COAL PLANTS FOR RETIREMENT ANALYSIS

COAL FACILITY	CAPACITY (MW WINTER)	CF% RANGE THROUGH 2035	YEARS IN SERVICE (AS OF 1/2020)	RANK
Allen 1 – 3	604	3% – 11%	60 – 62	1
Allen 4&5	526	2% - 9%	58 – 59	2
Cliffside 5	546	2% - 23%	47	3
Mayo	746	1% - 12%	36	4
Roxboro 1&2	1,053	5% - 34%	51 – 53	5
Roxboro 3&4	1,409	1% - 32%	39 – 46	6
Marshall 1-4	2,078	1% - 49%	49 – 54	7
Belews Creek 1&2	2,220	16% - 57%	44 – 45	8

Corrected 11.06.2020

Because the cost of replacement generation for coal plants is a critical factor when determining the value of retirement, the Company considered the capacity of the plant to be one of the most important factors for determining the order in which to conduct the retirement analysis. For instance, while Cliffside 5 has a higher capacity factor than Mayo, which would indicate Cliffside 5 has higher production cost value, the lower capacity of Cliffside 5 requires less replacement generation at the time of retirement. For this reason, Cliffside 5 was ranked above Mayo in the order for conducting the retirement analysis. Cliffside 6 was not evaluated in the ranking step as its ability to burn 100% natural gas provides flexibility that is valuable across the range of portfolios evaluated in this IRP.

STEP 2: SEQUENTIAL PEAKER METHOD (SPM)

Once the order to conduct the retirement analysis was determined, the next step was to determine the most economic date for each coal plant. As discussed above, as coal plants are retired, the value of the remaining coal plants in the fleet changes. For this reason, the Company evaluated the economic value of each plant in a sequential manner. Additionally, for determining the optimum retirement date, the Company used a Net Cost of New Entry (Net CONE) methodology when evaluating each plant. The Net CONE method is similar to the Peaker Method used in calculating avoided costs as it considers both the capital and fixed costs of a generic peaker, as well as, the net production cost value of the peaker versus the asset the peaker is replacing. Importantly, this step is used solely to determine the optimal date for retirement. In Step 3, or the Portfolio Optimization step, the optimum replacement generation is determined, considering alternative technology options such as solar, wind, battery storage, solar + storage, and natural gas generation to determine the lowest total cost resource mix to support the aggregate defined economic retirement dates.

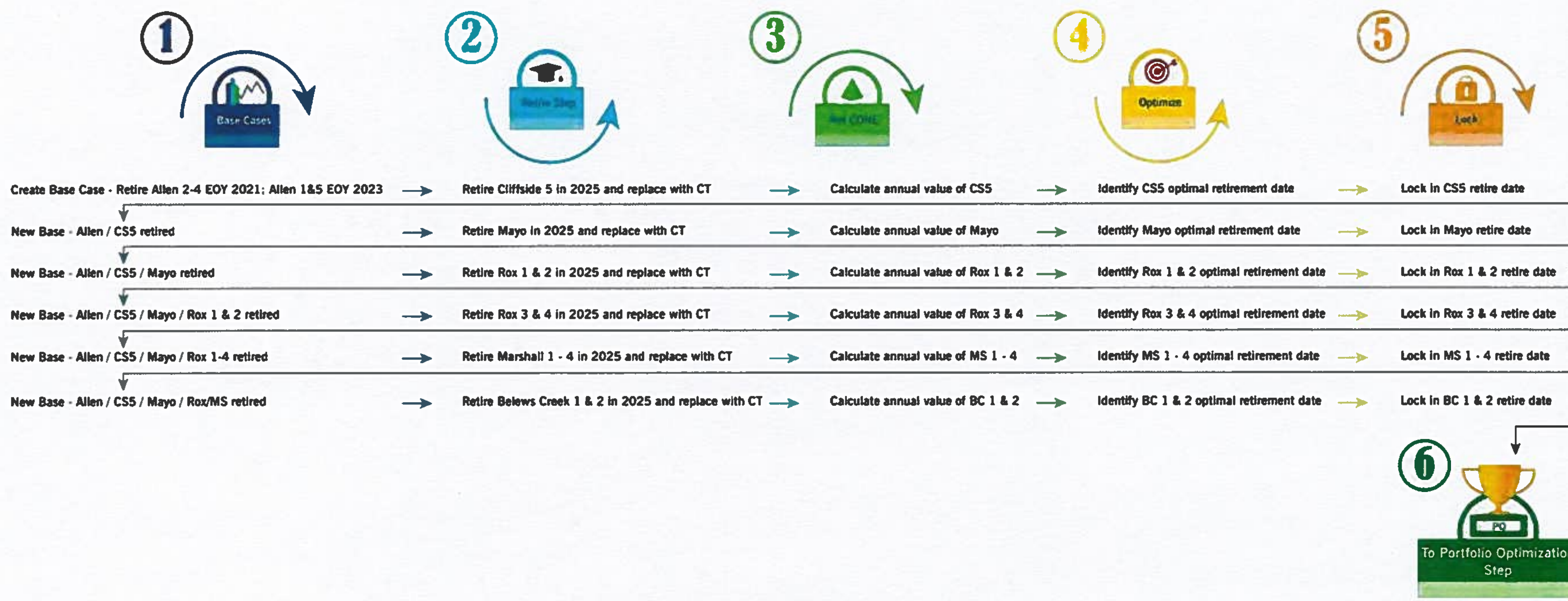
In addition to accelerating the cost of the replacement peaker and the impacts to the system variable production costs, the second step also considered the on-going capital and fixed operating costs avoided by accelerating the retirement date of the coal plant. For example, the avoided costs included any incremental coal ash management costs, including estimates for new landfill cells that would have been required to store incremental coal ash generated through continued operation of these plants.

Finally, the Sequential Peaker Method included the cost to accelerate transmission upgrades associated with the retirement of some of the coal plants. In several instances, the retiring coal plant or units provided support to the transmission system, and in those cases, the Company included the cost of Static Var Compensators (SVCs) and/or line upgrades to address the loss of generation on the system.

The figure below presents a high-level view of how the SPM analysis was conducted, and the results of the analysis are presented in Table 11-B. While not shown in the graphic below, Allen Units 1-5 were evaluated in an initial step once it was determined replacement generation would not be needed since there was sufficient capacity above reserve margin requirements prior to 2025. For all other units, the Company assumed replacement generation or the necessary transmission upgrades needed to retire the facilities would not be available until 2025, and therefore the earliest date any plant after Allen Units 1-5 could be retired was considered to be 2025.

FIGURE 11-B

SEQUENTIAL PEAKER METHOD PROCESS FOR DETERMING ECONOMIC RETIREMENT DATES OF COAL PLANTS



Corrected 11.06.2020

DUKE ENERGY CAROLINAS

The table below shows the economic retirement dates for each coal plant as determined via the Sequential Peaker Method.

TABLE 11-B
ECONOMIC RETIREMENT DATES OF COAL PLANTS FROM SPM

COAL PLANT	BASE CASE W/ CO_2 POLICY MOST ECONOMIC RETIREMENT YEAR (JAN 1)[1]
Allen 2 – 4	2022
Allen 1 & 5	2024
Cliffside 5	2026
Roxboro 3 & 4	2028
Roxboro 1 & 2	2029
Mayo 1	2029
Marshall 1 – 4	2035
Belews Creek 1	2039
Belews Creek 2	2039
Cliffside 6	2049

As demonstrated through the SPM step, Allen unit retirements in 2022 (YE 2021) and 2024 (YE 2023) and the associated new South Point switchyard, which is necessary to allow for the retirement of all five Allen units, will bring economic value to customers and further the clean energy goals held by the Company and stakeholders. As with all unit retirement dates in the IRP, this is not a commitment

[1] There was no appreciable difference between the economic retirement dates in the Base Case with Carbon policy and Base Case without Carbon policy.

to retire the Allen units on this timeline but rather contains the Company's most recent estimate of retirement economics at the time of this filing. Official retirement will require final management approval with final retirement dates contingent upon the finalization of the supporting switchyard project and other operational considerations.

With the potential retirement of Allen Steam Station on the horizon, it is noteworthy that the facility has provided reliable energy to the Carolinas for over 60 years.

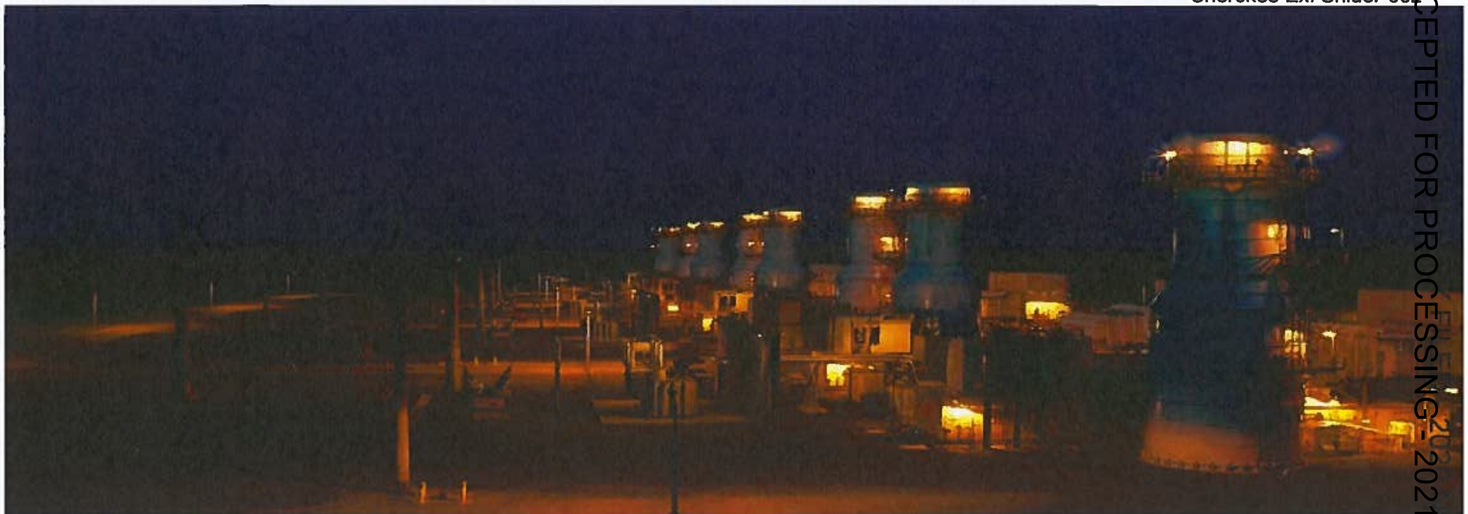
STEP 3: PORTFOLIO OPTIMIZATION

After the most economic retirement dates were determined, the Company relied on expansion plan and system production cost modeling to develop two optimized portfolios with the assumption that coal units were retired on the dates determined in Step 2. These optimized portfolios represent the Base Plan with Carbon Policy and Base Plan without Carbon Policy discussed in greater detail in Chapter 12 and Appendix A, and replacement generation includes a mix of solar, solar plus storage, standalone storage, wind, EE/DSM, and natural gas generation.

The development of these optimized portfolios was based on the best available projections of fuel, technology, carbon, and other costs known at the time the inputs to the IRP were developed. As the economics of continued coal operations change relative to the costs of replacement resource alternatives, future IRPs will reflect such changes. However, it is only when units are ultimately planned for retirement in the future, with specific replacement resources identified at specific locations, that the actual costs for replacement resources can be known. Importantly, with the exception of the Allen units, all further coal unit retirements will require replacement resources to be in service prior to the physical retirement of the coal facility in order to maintain system reliability. It is at that time that the actual costs of replacement resources from Step 4, or the Execution step, will be determined as part of a future CPCN and associated RFP process.

As previously noted, in addition to the most economic retirement dates for the coal plants, the Company also developed the earliest practicable retirement dates for each plant. The earliest practicable dates were determined without considerations of least cost planning, and they represent the earliest date plants could be retired when considering transmission, fuel, replacement generation, and other logistical requirements. The methodology and results of the earliest practicable retirement date analysis is presented in Appendix A.

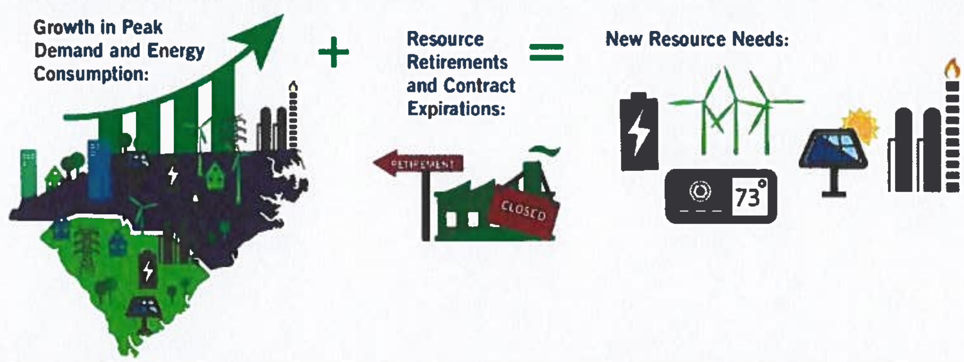
Corrected 11.06.2020



12 EVALUATION AND DEVELOPMENT OF THE RESOURCE PLAN

As described in Chapter 9, DEC continues to plan to winter planning reserve margin criteria in the IRP process. To meet the future needs of DEC's customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, DEC develops a load forecast of cumulative energy sales and hourly peak demand. To determine total resources needed, the Company considers the peak demand load obligation plus a 17% minimum planning winter reserve margin. The projected capability of existing resources, including generating units, EE and DSM, renewable resources and purchased power contracts is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation and planning reserve margin while complying with all environmental and regulatory requirements. A high-level representation of the IRP process is represented in Figure 12-A.

FIGURE 12-A
SIMPLIFIED IRP PROCESS



It should be noted that DEC considers the non-firm energy purchases and sales associated with the JDA with DEP in the development of its six portfolios, as discussed later in this chapter and in Appendix A.

THREE PILLARS OF THE IRP

The IRP process has changed as the industry has changed. While the intent of the IRP remains to develop a 15-year plan that is reliable and least cost to meet future customer demand, other factors also must be considered when selecting a plan.

FIGURE 12-B
THREE PILLARS OF THE IRP

There are three pillars which determine the primary planning objectives in the IRP. These pillars are as follows:

- **Environmental**
- Financial (Affordability)
- Physical (Reliability)

The Environmental pillar of the IRP process takes into consideration various policies set by state and federal entities. Such entities include NCUC, PSCSC, FERC, NERC, SERC, NRC, and EPA, along with various other state and federal regulatory entities. Each of these entities develops policies that have a direct bearing on the inputs, analysis and results of the IRP process. While many regulatory and legislative policies impact the production of the IRP, the primary focus on both a state and national level is around environmental policies. Examples of such policies include NC HB 589, SC Act 236 and SC Act 62 programs that set targets for the addition of renewable resources. Environmental legislation at the state and federal level can impact the cost and operations of existing resources, as well as future assets. In addition, reliability and operational requirements imposed on the system influence the IRP process.

The Financial, or Affordability, pillar is another basic criterion for the IRP. The plan that is selected must be cost-effective for the customers of the Company. DEC's service territory, located in the southern United States, has climate conditions that require more combined electric heating and cooling per customer than any other region in the country. As such, DEC's customers require more electricity than customers from other regions, highlighting the need for affordable power. Changing customer preferences and usage patterns will continue to influence the load forecast incorporated in the Company's IRPs. Furthermore, as new technologies are developed and continue to evolve, the costs of these technologies are projected to decline. These downward impacts are contemplated in the planning process and changes to those projections will be closely monitored and captured in future IRPs. Technology costs are discussed in more detail in Appendices A and G.

Finally, Physical Reliability is the third pillar of the IRP process. Reliability of the system is vitally important to meeting the needs of today's customers, as well as the future needs that come with substantial customer growth projected in the region. DEC's customers expect energy to be provided to them every hour of every day throughout the year without fail, today and into the future. To ensure the energy and capacity needs of the Company's customers are met, the Company continues to plan to a reasonable 17% reserve margin, which helps to ensure that the reliability of the system is maintained. A more detailed discussion of the reliability requirements of the DEC system is discussed in Chapter 9.

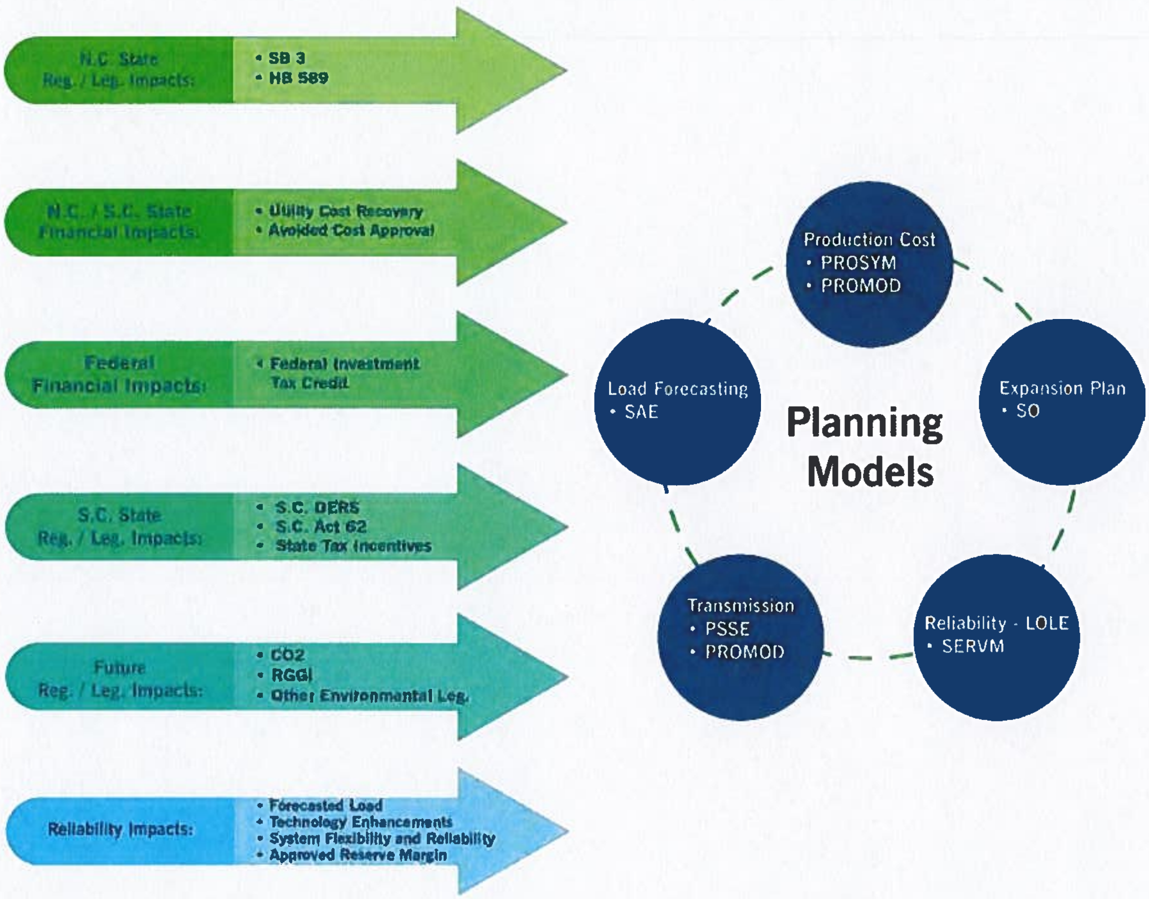
Each of these pillars must be evaluated and balanced in the IRP in order to meet the intent of the process. The Company has adhered to the principles of these pillars in the development of this IRP and the portfolios and scenarios evaluated as part of the IRP process.

Figure 12-C below graphically represents examples of how issues from each of the pillars may impact the IRP modeling process and subsequent portfolio development.

DUKE ENERGY CAROLINAS

FIGURE 12-C

IMPACTS OF THREE PILLARS ON THE IRP MODELING PROCESS



IRP ANALYSIS PROCESS

The following section summarizes the Data Input, Generation Alternative Screening, Portfolio Development and Detailed Analysis steps in the IRP process. A more detailed discussion of the IRP Process and development of the Base Cases and additional portfolios is provided in Appendix A.

DATA INPUTS

Refreshing input data is the initial step in the IRP development process. For the 2020 IRP, data inputs such as load forecast, EE and DSM projections, fuel prices, projected CO_2 prices, individual plant operating and cost information, and future resource information were updated with the most current data. These data inputs were developed and provided by Company subject matter experts and/or based upon vendor studies, where available. Furthermore, DEC and DEP continue to benefit from the combined experience of both utilities' subject matter experts utilizing best practices from each utility in the development of their respective IRP inputs. Where appropriate, common data inputs were utilized.

As expected, certain data elements and issues have a larger impact on the IRP than others. Any changes in these elements may result in a noticeable impact to the plan, and as such, these elements are closely monitored. Some of the most consequential data elements are listed below. A detailed discussion of each of these data elements has been presented throughout this document and are examined in more detail in the appendices.

- Load Forecast for Customer Demand
- EE/DSM Forecast
- Environmental Legislation and Regulation
- Renewable Resources and Cost Projections
- Fuel Costs Forecasts
- Technology Costs and Operating Characteristics

GENERATION ALTERNATIVE SCREENING

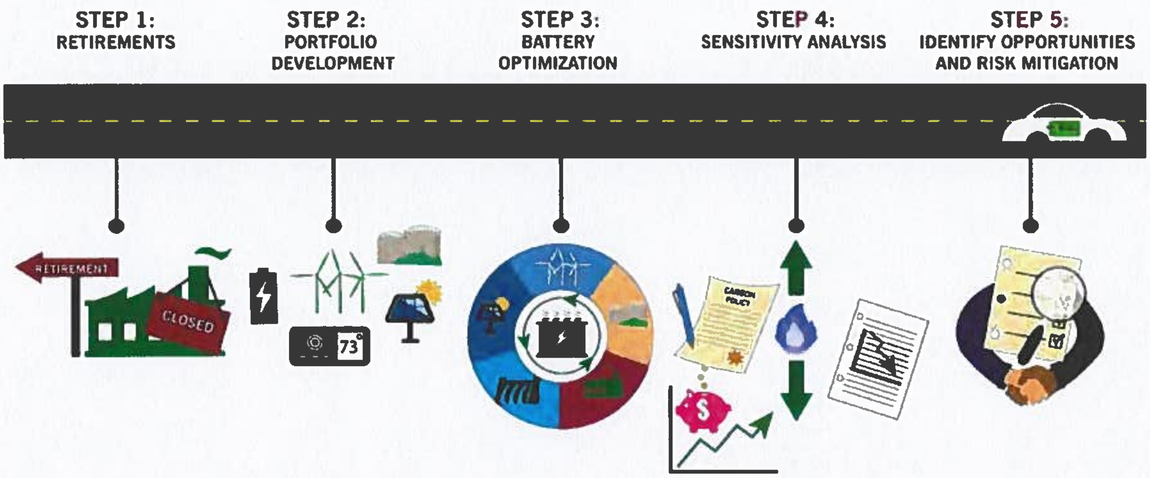
DEC reviews generation resource alternatives on a technical and economic basis. Resources must also be demonstrated to be commercially available for utility scale operations. The resources that are found to be both technically and economically viable are then passed to the detailed analysis process for further evaluation. The process of screening these resources is discussed in detail in Appendix G.

PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS

The following figure provides an overview of the process for the portfolio development and detailed analysis phase of the IRP. The process is discussed in detail in Appendix A.

FIGURE 12-D

OVERVIEW OF PORTFOLIO DEVELOPMENT AND SENSITIVITY ANALYSIS PHASE



The Base Case Portfolio Development and Sensitivity Analysis phases rely upon the updated data inputs and results of the generation alternative screening process to derive resource portfolios or resource plans. The Base Case Portfolio Development and Sensitivity Analysis phases utilize an expansion planning model, System Optimizer (SO), to determine the best mix of capacity additions for the Company's short- and long-term resource needs with an objective of selecting a robust plan that meets reliability targets, minimizes the PVRR to customers and is environmentally sound by complying with or exceeding all State and Federal regulations.

Sensitivity analysis of input variables such as load forecast, fuel costs, renewable energy, EE, and resource capital costs are considered as part of the quantitative analysis within the resource planning process. Utilizing the results of these sensitivities, possible expansion plan options for the DEC system are developed. These expansion plans are reviewed to determine if any overarching trends are present across the plans, and based on this analysis, portfolios are developed to represent these trends. Finally, the portfolios are analyzed using a capital cost model and an hourly production cost model (PROSYM) under various fuel price and carbon scenarios to evaluate the robustness and economic value of each portfolio under varying input assumptions. After this comprehensive analysis is completed, the portfolios are examined considering the trade-offs between costs, carbon reductions, and dependency on technological and policy advancements.

Corrected 11.06.2020

In addition to evaluating these portfolios solely within the DEC system, the potential benefits of sharing capacity within DEC and DEP are examined in a common Joint Planning Case. A detailed discussion of these portfolios is provided in Appendix A.

SELECTED PORTFOLIOS

For the 2020 IRP, six portfolios were identified through the Base Case Portfolio Development and Sensitivity Analysis process that consider and attempt to address stakeholder interest in the transformation of the DEC generation fleet. As described below, the portfolios range from diverse intended outcomes ranging from least cost planning to high carbon reductions and resource restrictions. Additionally, some portfolios consider the increase in the amount and adoption rate of renewables, EE, and energy storage to achieve these outcomes.

PORTFOLIO A (BASE CASE WITHOUT CARBON POLICY)

This portfolio primarily selects new natural gas generation to meet load growth and replace retiring existing capacity. This case incorporates the most economic retirement dates for the coal units, as discussed in Chapter 11, which includes the retirement of 3,800 MW of coal capacity by the end of the IRP planning period. The base planning assumptions for expected renewable additions and interconnections, energy efficiency and demand response are also built into this plan, before a new resource is considered. Although no renewable resources were economically selected by the model, this case adds 2,700 MW of solar and solar plus storage throughout the IRP planning horizon. This plan also adds 150 MW of battery storage placeholders to the system in the early- to mid-2020s. These battery storage options have the potential to provide solutions for the transmission and distribution systems, while simultaneously providing benefits to the generation resource portfolio. Overall, this plan adds 4,300 MW of CC and CT gas capacity beginning in the winter of 2029 to ensure the utility can meet customer load demand.

PORTFOLIO B (BASE CASE WITH CARBON POLICY)

This portfolio assumes the same base planning assumptions as the previous case but is developed with the IRP's base carbon tax policy as a proxy for future carbon legislation. This case adds 3,100 MW of natural gas capacity and pushes the DEC first need from winter of 2029 to winter of 2030. While less natural gas generation is built in the plan, renewable resources begin to be economically selected to meet demand. This plan selects 2,000 MW of incremental solar and solar plus storage

Corrected 11.06.2020

than included in the base forecast and in the Base Case without Carbon Policy. This plan also begins to incorporate onshore central Carolinas wind, adding 150 MW in the last year of the planning horizon. These changes are a direct result of the carbon tax, which increases prices on carbon-intense resources like coal. The inclusion of the carbon tax in the development of this case clearly changes the resource selection, favoring more carbon free resources to meet the Company's energy needs.

PORTFOLIO C (EARLIEST PRACTICABLE COAL RETIREMENTS)

This portfolio focuses on DEC's ability to retire or cease burning coal at its existing coal units as early as practicable. Several factors were considered in the establishment of these retirement dates and are discussed in detail in Appendix A. The earliest practicable retirement analysis resulted in the acceleration of Marshall station from 2035 in the Base Cases to 2028 and Belews Creek from outside the IRP planning window to 2029. Cliffside 5's retirement date remains the same as the most economic retirement date at the end of 2025. On the other hand, Cliffside 6 ceases to burn coal by the end of 2029, but continues to provide flexibility and reliability as a natural gas-burning unit through the IRP study period. Part of the analysis for earliest practicable retirement dates requires construction and transmission upgrades and interconnection costs for replacement generation. Additionally, the retirement of the coal units was expedited by leveraging existing infrastructure to eliminate the need for transmission upgrades and/or new gas pipelines, as would be required at new replacement generation sites. Replacing over 6,800 MW of coal capacity requires extensive firm capacity additions to the DEC system. As such, this plan results in the acceleration of CT and CC capacity additions from later in the plan and outside the planning horizon to coincide with the coal retirements in order to capitalize on the existing gas and transmission infrastructure at the retiring coal sites. Further, additional transmission upgrades are avoided by siting replacement gas generation at the Marshall and Belews Creek stations. As with the Base Case with Carbon Policy scenario, this case also adds nearly 5,000 MW of solar and solar plus storage to replace retiring coal generation in order to meet DEC's future energy and capacity needs.

PORTFOLIO D (70% CO_2 REDUCTIONS: HIGH WIND)

This portfolio outlines a pathway for the Carolinas combined system to achieve 70% CO_2 reductions, from a 2005 baseline, by tapping into wind resources off the coast of the Carolinas. This plan leverages high energy efficiency and demand response projections, as well as high penetration renewables forecasts with increased solar annual integration limits. The combination of these resources further reduces carbon by adding 7,500 total MW of solar and solar plus storage.

Additionally, 1,500 MW of land-based wind, from both central Carolinas and midcontinental U.S. is included. This portfolio also utilizes the earliest practicable retirement dates as established in Portfolio C with the associated replacement capacity to enable those retirements. It is worth noting that even with assumptions of high EE, DR, and renewables, combined with accelerated coal retirements do not get the combined system to 70% CO_2 reductions by 2030. In order to reach 70%, the Company adds 1,200 MW of offshore wind into the DEC system for the winter peak of 2030. For a long lead time infrastructure project such as this, the retirements of one of the Belews Creek units is delayed from 2029 to 2030 to maintain planning reserve capacity until the offshore wind can be operational.

PORTFOLIO E (70% CO_2 REDUCTION: HIGH SMR)

This portfolio outlines a pathway for the Carolinas combined system to achieve 70% CO_2 reductions, from a 2005 baseline, by deploying advanced nuclear technologies by the end of this decade. This plan also leverages high energy efficiency and demand response projections as well as high penetration renewables forecasts with increased solar annual integration limits. The combination of these inputs further reduces carbon by adding 7,500 total MW of solar and solar plus storage. As in Portfolio D, 1,500 MW of land-based wind, from both central Carolinas and midcontinental U.S. is included. This portfolio also utilizes the earliest practicable retirement dates as established in Portfolio C with the associated replacement capacity to enable those retirements. Again, it is worth noting that even with assumptions of high EE, DR, and renewables, combined with accelerated coal retirements do not get the combined system to 70% CO_2 reductions by 2030. In order to reach 70%, a 684 MW small modular nuclear reactor plant[1] is added to the DEC system at the beginning of 2030. For a long lead time infrastructure project such as this, the retirements of one of the Belews Creek units was delayed from 2028 to 2030 to maintain planning reserve capacity until the SMR can be operational.

PORTFOLIO F (NO NEW GAS GENERATION)

This portfolio addresses growing interest from stakeholders and Environmental, Social and Governance (ESG) investors to understand the impacts of transitioning the current DEC portfolio to a

[1] As described in Appendix A, the first full-scale, commercial SMR project is slated for completion at the start of the next decade which is the same time period as the plant in this scenario. To complete a project of this magnitude would require a high level of coordination between state and federal regulators, and even with that assumption, the timeline is still challenged based on the current licensing and construction timeline required to bring this technology to DEC.

Corrected 11.06.2020

net-zero carbon portfolio by 2050, without the deployment of new gas generation. Because the earliest practicable coal retirement dates are predicated on replacement with gas generation at some of the retiring coal sites, Portfolio F uses to the most economic coal retirement dates as utilized in the Base Cases. To minimize costs to customers, without the ability to build gas, high EE and DR projections as well as, high penetration renewables forecasts combined with increased solar annual integration limits are included in this plan. With the later retirement dates, and aided by the high forecasts of EE, DR and renewables, a capacity need does not appear in DEC until 2035 when Marshall station is retired. This energy and capacity need created by the retirement of Marshall station is met with Pumped Storage hydro and new Nuclear SMRs. As with portfolios D and E, significant intermittent generation increases the value of energy storage, which allows the capacity need to be met, in part, by adding 1,600 MW of pumped storage hydro capacity. The remainder of the capacity need is met with the deployment of a new small modular nuclear plant, providing 684 MW of firm, flexible capacity. With its modular design and ability to adjust output based on demand needs, this non-gas generation source can provide the necessary reliability and flexibility needed by the DEC system. Additionally, this plan adds 7,500 MW of solar and solar plus storage and 1,500 MW of land-based wind from both central Carolinas and mid-continental U.S.

PORTFOLIO ANALYSIS

The six portfolios developed from the Base Case and Portfolio Development and Sensitivity phase and informed by the Base Case sensitivity analysis, were evaluated in more detail utilizing an hourly production cost model under a matrix of nine carbon and fuel cost scenarios. The results of these hourly production cost model runs were paired with the accompanying capital costs and analyzed focusing on the trade-offs between cost, carbon reductions, and dependency on technological and policy advancements. Table 12-A below illustrates the scenario matrix, in which each portfolio was tested.

DUKE ENERGY CAROLINAS

TABLE 12-A

SCENARIO MATRIX FOR PORTFOLIO ANALYSIS

	NO CO_2	BASE CO_2	HIGH CO_2
Low Fuel			
Base Fuel			
High Fuel			

Table 12-B details the results of the PVRR analysis under the varying carbon and fuel scenarios with the cost of the carbon tax excluded, while Table 12-C provides the same results but includes the cost of a carbon tax.

DUKE ENERGY CAROLINAS

TABLE 12-B

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON (2020 DOLLARS IN BILLIONS)

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$51.5	$52.3	$52.5	$60.3	$58.0	$60.4
High CO_2-Base Fuel	$46.2	$47.5	$47.1	$56.3	$53.9	$56.5
High CO_2-Low Fuel	$42.4	$43.9	$43.5	$53.4	$51.1	$53.8
Base CO_2-High Fuel	$50.6	$51.2	$52.2	$60.1	$57.6	$59.8
Base CO_2-Base Fuel	$45.8	$46.8	$46.8	$56.1	$53.6	$56.0
Base CO_2-Low Fuel	$42.0	$43.4	$43.1	$53.2	$50.7	$53.2
No CO_2-High Fuel	$49.3	$49.4	$51.2	$59.5	$56.6	$58.3
No CO_2-Base Fuel	$44.4	$44.9	$45.8	$55.5	$52.6	$54.6
No CO_2-Low Fuel	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Min	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Median	$45.8	$46.8	$46.8	$56.1	$53.6	$56.0
Max	$51.5	$52.3	$52.5	$60.3	$58.0	$60.4

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

TABLE 12-C

SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON (2020 DOLLARS IN BILLION)

	BASE PLANNING WITHOUT CARBON POLICY	BASE PLANNING WITH CARBON POLICY	EARLIEST PRACTICABLE COAL RETIREMENTS	70% CO_2 REDUCTION: HIGH WIND	70% CO_2 REDUCTION: HIGH SMR	NO NEW GAS GENERATION
High CO_2-High Fuel	$65.9	$64.0	$63.8	$68.3	$65.4	$68.4
High CO_2-Base Fuel	$59.8	$58.5	$58.3	$64.2	$61.3	$64.0
High CO_2-Low Fuel	$55.8	$54.9	$54.7	$61.3	$58.4	$61.1
Base CO_2-High Fuel	$61.8	$60.4	$60.5	$66.0	$63.1	$65.9
Base CO_2-Base Fuel	$55.9	$55.1	$55.0	$61.9	$59.0	$61.6
Base C_O2-Low Fuel	$51.9	$51.4	$51.4	$59.1	$56.2	$58.7
No CO_2-High Fuel	$49.3	$49.4	$51.2	$59.5	$56.6	$58.3
No CO_2-Base Fuel	$44.4	$44.9	$45.8	$55.5	$52.6	$54.6
No CO_2-Low Fuel	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Min	$40.8	$41.6	$42.1	$52.7	$49.7	$51.7
Median	$55.8	$54.9	$54.7	$61.3	$58.4	$61.1
Max	$65.9	$64.0	$63.8	$68.3	$65.4	$68.4

BASE CASE WITH CARBON POLICY

Each of the alternative portfolios provides insight on strategies and advancements necessary to further evaluate carbon reductions and cost trade-offs. However, for planning purposes, Duke Energy considers the least cost, reliable cases as the Base Case with Carbon Policy and Base Case without Carbon Policy portfolios. These least cost portfolios meet the current IRP rules and regulations currently in place in NC and SC. If a carbon constrained future is either delayed or is more restrictive than base assumptions, or other variables, such as fuel price and capital costs change significantly from the base assumptions, the selected carbon constrained portfolio remains adequately robust to provide value in those futures. Another factor that is considered when selecting the base portfolio is the likelihood that the selected portfolio can be executed as presented.

Portfolio B, Base Case with Carbon Policy, is presented below and includes the addition of a diverse compilation of resources including CCs, CTs, battery storage, EE, DSM and significant amounts of solar, solar plus storage and wind. These resources are selected in conjunction with existing nuclear, natural gas, expected renewable projections and other assets already on the DEC system. This portfolio also enables the Company to lower carbon emissions under a range of future scenarios at a lower cost than most other scenarios.

Finally, the Base Case with Carbon Policy portfolio was developed utilizing consistent assumptions and analytic methods between DEC and DEP, where appropriate. This case does not consider the sharing of capacity between DEC and DEP. However, the Base Case incorporates the JDA between DEC and DEP, which represents a non-firm energy only commitment between the Companies. A Joint Planning Case that begins to explore the potential for DEC and DEP to share firm capacity was also developed and is discussed in Appendix A.

The Load and Resource Balance graph shown in Figure 12-E illustrates the resource needs required for DEC to meet its load obligation inclusive of a required 17% reserve margin. Existing generating resources, designated and expected resource additions and EE/DSM resources do not meet the required load and reserve margin beginning in 2030. As a result, the Base Case with Carbon Policy plan is presented to meet this resource gap.

DUKE ENERGY CAROLINAS

FIGURE 12-E

DEC BASE CASE WITH CARBON POLICY LOAD RESOURCE BALANCE (WINTER)

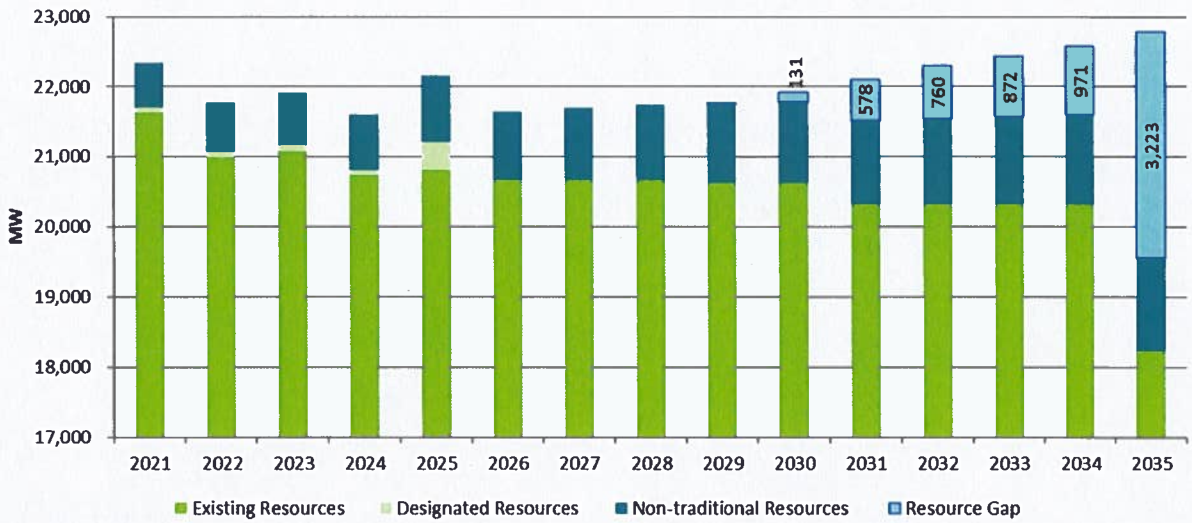


TABLE 12-D

CUMULATIVE RESOURCE ADDITIONS TO MEET WINTER LOAD OBLIGATION AND RESERVE MARGIN (MW)

YEAR	2021	2022	2023	2024	2025	2026	2027	2028
Resource Need	0	0	0	0	0	0	0	0

YEAR	2029	2030	2031	2032	2033	2034	2035
Resource Need	0	131	578	760	872	971	3,223

Tables 12-E and 12-F present the Load, Capacity and Reserves (LCR) tables for the Base Case with Carbon Policy analysis that was completed for DEC's 2020 IRP.

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

TABLE 12-E

BASE CASE WITH CARBON POLICY LOAD, CAPACITY AND RESERVES TABLE - WINTER

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load Forecast																
1	DEC System Winter Peak	17,795	17,933	18,042	18,195	18,334	18,493	18,607	18,790	18,933	19,074	19,226	19,393	19,502	19,605	19,752
2	Catawba Owner Backstand - NCEMC	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
3	Cumulative New EE Programs	(70)	(129)	(183)	(233)	(303)	(346)	(382)	(410)	(430)	(437)	(436)	(431)	(421)	(405)	(377)
4	**Adjusted Duke System Peak**	17,823	17,903	17,957	18,061	18,130	18,246	18,324	18,478	18,601	18,736	18,889	19,061	19,180	19,298	19,473
Existing and Designated Resources																
5	Generating Capacity	21,447	21,518	20,900	20,995	20,634	21,036	20,490	20,490	20,490	20,490	20,490	20,317	20,317	20,317	20,317
6	Designated Additions / Uprates	71	86	95	65	402										
7	Retirements / Derates	-	(704)	-	(426)	-	(546)	-	-	-	-	(173)	-	-	-	(2,078)
8	**Cumulative Generating Capacity**	21,518	20,900	20,995	20,634	21,036	20,490	20,490	20,490	20,490	20,490	20,317	20,317	20,317	20,317	18,239
Purchase Contracts																
9	**Cumulative Purchase Contracts**	212	210	186	189	190	186	188	187	150	150	20	11	11	10	10
	Non-Compliance Renewable Purchases	37	40	17	18	19	13	13	13	12	12	12	11	11	10	10
	Non-Renewables Purchases	176	170	169	171	171	173	174	174	137	138	8	-	-	-	-
Undesignated Future Resources																
10	Nuclear															
11	Combined Cycle															1,224
12	Combustion Turbine										457	457				913
13	Solar					1	1	1	1	20	20	20	39	39	39	39
14	Wind															50
15	Battery															
Renewables																
16	**Cumulative Renewables Capacity**	103	115	109	118	105	108	139	164	213	247	276	315	353	407	504
	Renewables w/o Storage	103	91	81	83	62	59	60	55	56	53	45	28	19	17	17
	Solar w/ Storage (Solar Component)	-	1	1	2	2	2	3	5	6	6	7	7	7	7	7
	Solar w/ Storage (Storage Component)	-	23	27	34	40	45	73	101	129	146	163	180	188	205	214
17	**Combined Heat & Power**	16	30	30	-	-	-	-	-	-	-	-	-	-	-	-
18	**Grid-connected Energy Storage**	9	20	25	25	25	25	25	-	-	-	-	-	-	-	-
19	**Cumulative Production Capacity**	21,859	21,300	21,421	21,096	21,511	20,989	21,047	21,070	21,083	21,674	21,756	21,787	21,826	21,877	22,033
Demand Side Management (DSM)																
20	**Cumulative DSM Capacity**	478	467	468	470	473	476	484	497	513	534	558	585	611	635	656
21	**IVVC Peak Shaving**	-	-	17	34	173	174	176	177	179	180	182	184	185	187	189
22	**Cumulative Capacity w/ DSM**	22,337	21,767	21,905	21,600	22,157	21,639	21,707	21,744	21,775	22,288	22,497	22,556	22,621	22,700	22,878
Reserves w/ DSM																
23	Generating Reserves	4,513	3,865	3,948	3,539	4,027	3,392	3,383	3,266	3,174	3,553	3,608	3,494	3,441	3,402	3,405
24	**% Reserve Margin**	25.3%	21.6%	22.0%	19.6%	22.2%	18.6%	18.5%	17.7%	17.1%	19.0%	19.1%	18.3%	17.9%	17.6%	17.5%

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

TABLE 12-F:

BASE CASE WITH CARBON POLICY LOAD, CAPACITY AND RESERVES TABLE – SUMMER

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
	Load Forecast															
1	DEC System Winter Peak	17,795	17,933	18,042	18,195	18,334	18,493	18,607	18,790	18,933	19,074	19,226	19,393	19,502	19,605	19,752
2	Catawba Owner Backstand - NCEMC	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
3	Cumulative New EE Programs	(70)	(129)	(183)	(233)	(303)	(346)	(382)	(410)	(430)	(437)	(436)	(431)	(421)	(405)	(377)
4	**Adjusted Duke System Peak**	17,823	17,903	17,957	18,061	18,130	18,246	18,324	18,478	18,601	18,736	18,889	19,061	19,180	19,298	19,473
	Existing and Designated Resources															
5	Generating Capacity	21,447	21,518	20,900	20,995	20,634	21,036	20,490	20,490	20,490	20,490	20,490	20,317	20,317	20,317	20,317
6	Designated Additions / Uprates	71	86	95	65	402										
7	Retirements / Derates	-	(704)	-	(426)	-	(546)	-	-	-	-	(173)	-	-	-	(2,078)
8	**Cumulative Generating Capacity**	21,518	20,900	20,995	20,634	21,036	20,490	20,490	20,490	20,490	20,490	20,317	20,317	20,317	20,317	18,239
	Purchase Contracts															
9	**Cumulative Purchase Contracts**	212	210	186	189	190	186	188	187	150	150	20	11	11	10	10
	Non-Compliance Renewable Purchases	37	40	17	18	19	13	13	13	12	12	12	11	11	10	10
	Non-Renewables Purchases	176	170	169	171	171	173	174	174	137	138	8	-	-	-	-
	Undesignated Future Resources															
10	Nuclear															
11	Combined Cycle															1,224
12	Combustion Turbine										457	457				913
13	Solar					1	1	1	1	20	20	20	39	39	39	39
14	Wind															50
15	Battery															
	Renewables															
16	**Cumulative Renewables Capacity**	103	115	109	118	105	108	139	164	213	247	276	315	353	407	504
	Renewables w/o Storage	103	91	81	83	62	59	60	55	56	53	45	28	19	17	17
	Solar w/ Storage (Solar Component)	-	1	1	2	2	2	3	5	6	6	7	7	7	7	7
	Solar w/ Storage (Storage Component)	-	23	27	34	40	45	73	101	129	146	163	180	188	205	214
17	**Combined Heat & Power**	16	30	30	-	-	-	-	-	-	-	-	-	-	-	-
18	**Grid-connected Energy Storage**	9	20	25	25	25	25	25	-	-	-	-	-	-	-	-
19	**Cumulative Production Capacity**	21,859	21,300	21,421	21,096	21,511	20,989	21,047	21,070	21,083	21,574	21,756	21,787	21,825	21,877	22,033
	Demand Side Management (DSM)															
20	**Cumulative DSM Capacity**	478	467	468	470	473	476	484	497	513	534	558	585	611	635	656
21	**IVVC Peak Shaving**	-	-	17	34	173	174	176	177	179	180	182	184	185	187	189
22	**Cumulative Capacity w/ DSM**	22,337	21,767	21,905	21,600	22,157	21,639	21,707	21,744	21,775	22,288	22,497	22,555	22,621	22,700	22,878
	Reserves w/ DSM															
23	Generating Reserves	4,513	3,865	3,948	3,539	4,027	3,392	3,383	3,266	3,174	3,553	3,608	3,494	3,441	3,402	3,405
24	**% Reserve Margin**	25.3%	21.6%	22.0%	19.6%	22.2%	18.6%	18.5%	17.7%	17.1%	19.0%	19.1%	18.3%	17.9%	17.6%	17.5%

Corrected 11.06.2020

TABLE 12-G

DEC - ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLES

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves tables. All values are MW (winter ratings) except where shown as a percent.

LINE ITEM	LINE INCLUSION[2]
1.	Peak demand for the Duke Energy Carolinas System as defined in Chapter 3 and Appendix C.
2.	Firm Catawba backstand for NCEMC. (579 MW * 17% RM) = 98 MW [3]
3.	Cumulative new energy efficiency and conservation programs (does not include demand response programs).
4.	Peak load adjusted for firm sales, NCEMC backstand and cumulative energy efficiency.
5.	Existing generating capacity reflecting the impacts of designated additions, planned uprates, retirements and derates as of January 1, 2020.
	Includes 103 MW Nantahala hydro capacity.
	Includes only DEC portion of Catawba Nuclear Station capacity.
	Includes Lee CC capacity of 683 MW, which is net of NCEMC ownership of 100 MW.
6.	Designated Capacity Additions
	Bad Creek Runner upgrades (65 MW per unit deployed in years 2021-2024).
	Lincoln CT 17 of 402 MW in 2025.
	Nuclear uprates: Oconee 1-3; 15 MW per unit deployed in years 2022-2023. Catawba 1 and 2; 6 MW per unit deployed in years 2021-2022.
7.	Estimated retirement dates for planning that represent most economical retirement date for coal units as determined in Coal Retirement Analysis discussed in Chapter 11. Other units represent estimated retirement dates based on the depreciation study approved in the most recent DEC rate case: Allen 2-4 (704 MW): December 2021 Allen 1 and 5 (426 MW): December 2023 Cliffside 5 (546 MW): December 2025 Marshall 1-4 (2,078 MW): December 2034 Lee 3 NG Boiler (173 MW): December 2030
	All nuclear units are assumed to have subsequent license renewal at the end of the current license.
	All hydro facilities are assumed to operate through the planning horizon.
	All retirement dates are subject to review on an ongoing basis. Dates used in the 2020 IRP are for planning purposes only, unless the unit is already planned for retirement.
8.	Sum of lines 5 through 7.

[2] Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the following year.
[3] NCEMC load was excluded in the 2020 load forecast per Commission order and as such, the NCEMC capacity was also removed from the total DEC generating assets. DEC is still responsible for backstanding the NCEMC capacity.

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

LINE ITEM	LINE INCLUSION
9.	Cumulative Purchase Contracts from traditional resources and renewable energy resources not used for NCREPS and NC HB 589 compliance. This is the sum of the next two lines.
	Non-Compliance Renewable Purchases includes purchases from renewable energy resources for which DEC does not own the REC.
	Non-Renewables Purchases are those purchases made from traditional generating resources.
10.	New nuclear resources economically selected to meet load and minimum planning reserve margin. No nuclear resources were selected in the Base Case with Carbon Policy in this IRP.
11.	New combined cycle resources economically selected to meet load and minimum planning reserve margin. Addition of 1,224 MW of combined cycle capacity online December 2034.
12.	New combustion turbine resources economically selected to meet load and minimum planning reserve margin. The case presented has the addition of the following CTs: 457 MW CT in December 2029 457 MW CT in December 2030 913 MW CTs in December 2034
13.	New solar resources economically selected to meet load and minimum planning reserve margin. The value in the table represents the contribution to peak of the selected solar facilities. (1% for winter peak and 40% for total solar < 999 MW reducing to 10% for total solar >3,600 MW for summer peak; Solar + Storage is approximately 25% in both summer and winter). The case presented has the addition of the following solar resources: Solar Only: 0.75 MW (75 MW nameplate) in each year 2025 through 2031; 1.5 MW (150 MW nameplate) in each year 2032 through 2035. Solar + Storage: 19 MW (75 MW nameplate) in each year 2029 through 2031; 37.5 MW (150 MW nameplate) in each year 2032 through 2035.
14.	New wind resources economically selected to meet load and minimum planning reserve margin. The value in the table represents the contribution to peak of the selected wind facilities. (33% for winter peak 7% for summer peak). The case presented has the addition 150 MW of wind resources in December 2034.
15.	New battery storage resources economically selected to meet load and minimum planning reserve margin. No battery resources were selected for DEC in the Base Case with Carbon Policy in this IRP.
16.	Cumulative Renewable Energy Contracts and renewable energy resources used for NCREPS and NC HB589 compliance. This is the sum of the next three lines and the selected cumulative renewable resources in lines 13-15.
	Renewables w/o Storage includes projected purchases from solar energy resources not paired with storage.
	Solar w/ Storage (Solar Component) includes the solar component of projected solar energy resources paired with storage.
	Solar w/ Storage (Storage Component) includes the storage component of projected solar energy resources paired with storage.

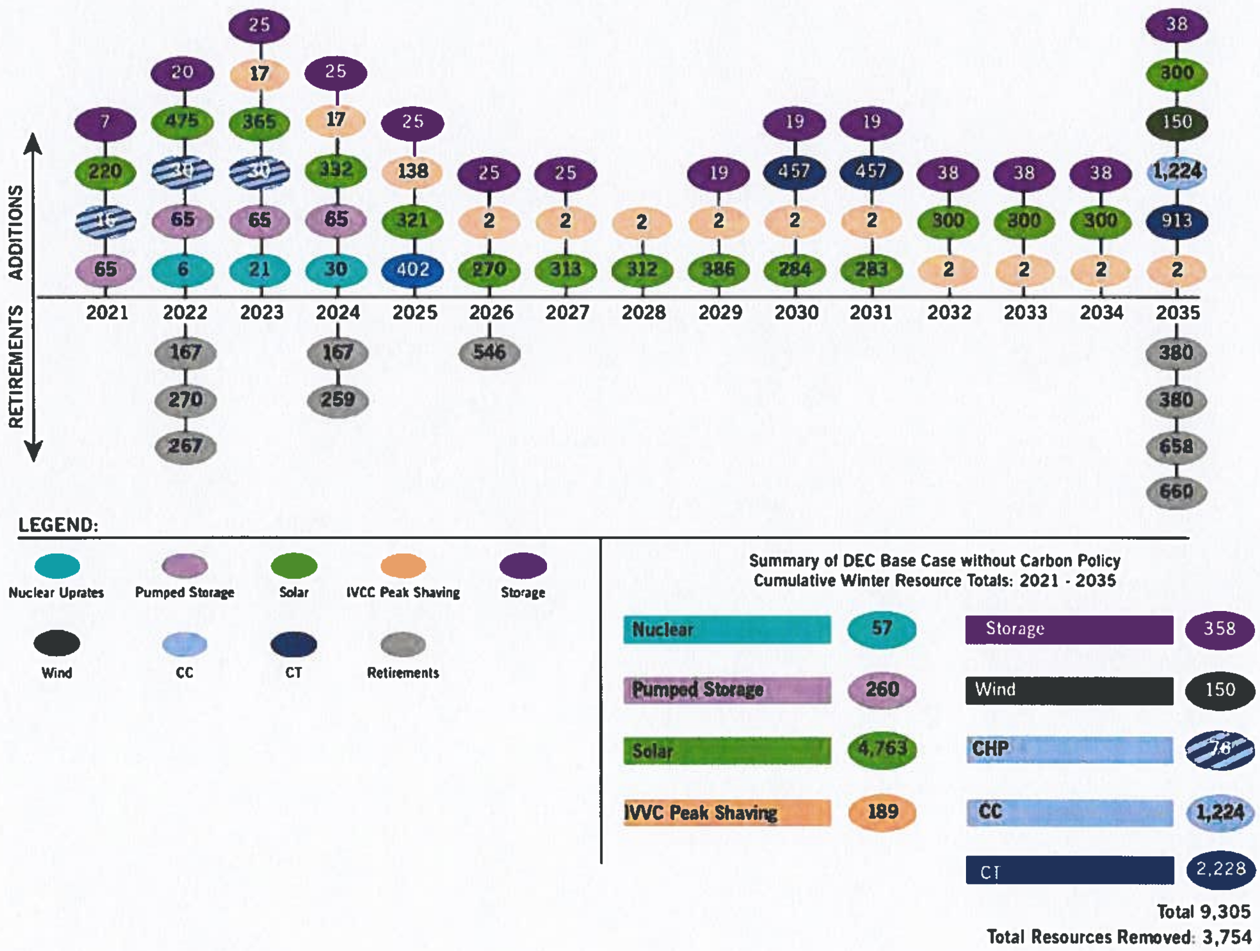
DUKE ENERGY CAROLINAS

LINE ITEM	LINE INCLUSION
17.	Combined Heat and Power projects. This plan includes 15.7 MW Clemson CHP in 2021 and 30 MW CHP placeholders in 2022 and 2023.
18.	Addition of 154 MW of grid-tied energy storage over the years 2021 through 2027.
19.	Cumulative total of lines 8 through 18.
20.	Cumulative demand response programs including wholesale demand response.
21.	Cumulative capacity associated with peak shaving of IVVC program.
22.	Sum of lines 19 through 21.
23.	The difference between lines 22 and 4.
24.	Reserve Margin RM = (Cumulative Capacity-System Peak Demand)/System Peak Demand. Line 23 divided by Line 4. Minimum winter target planning reserve margin is 17%.

DUKE ENERGY CAROLINAS

A graphical presentation of the Winter Base Case with Carbon Policy resource plan as represented in the above LCR table is shown below in Figure 12-F. This figure provides annual incremental capacity additions to the DEC system by technology type. Additionally, a summary of the total resources by technology is provided below the figure.

FIGURE 12-F
DEC BASE CASE WITH CARBON POLICY - ANNUAL ADDITIONS BY TECHNOLOGY

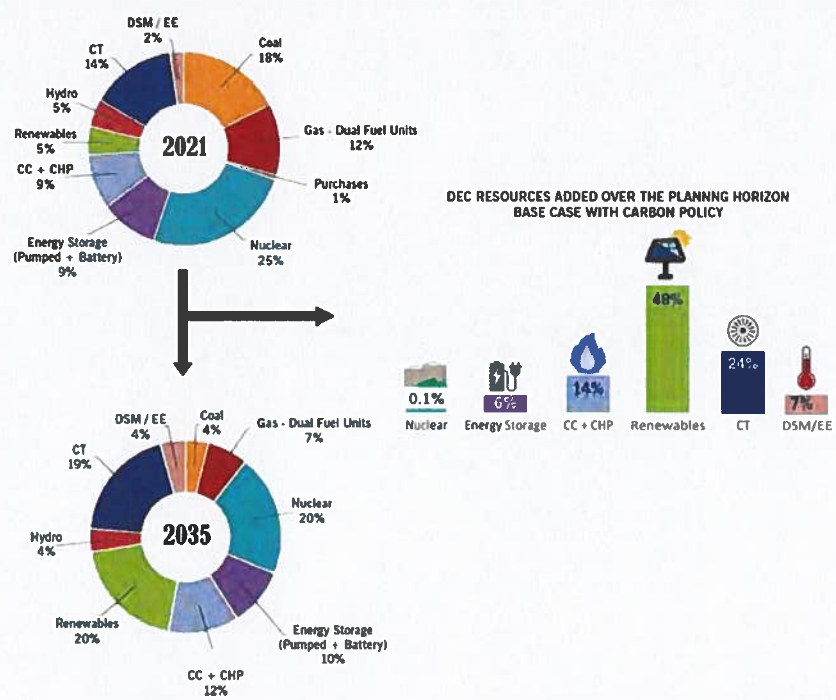


The following figures illustrate both the current and forecasted capacity for the DEC system, as projected by the Base Case with Carbon Policy. Figure 12-G depicts how the capacity mix for the DEC system changes with the passage of time. In 2035, the Base Case with Carbon Policy projects that DEC will have a substantial reduction in its reliance on coal and gas from steam units and a significantly higher reliance on renewable resources as compared to the current state. It is of particular note that nearly 50% of the new resources added over the study period are solar and wind resources.

As mentioned above, the Company's Base Case with Carbon Policy resources depicted in Figure 12-G below reflects a significant amount of growth in solar capacity with nameplate solar growing from 966 MW in 2021 to 4,016 MW by 2035. However, given that solar resources only contribute approximately 1% of nameplate capacity at the time of the Company's winter peak, solar capacity contribution to winter peak only grows from 10 MW in 2021 to 39 MW by 2035.

FIGURE 12-G

DEC CAPACITY OVER 15-YEAR STUDY PERIOD
BASE CASE WITH CARBON POLICY [4]

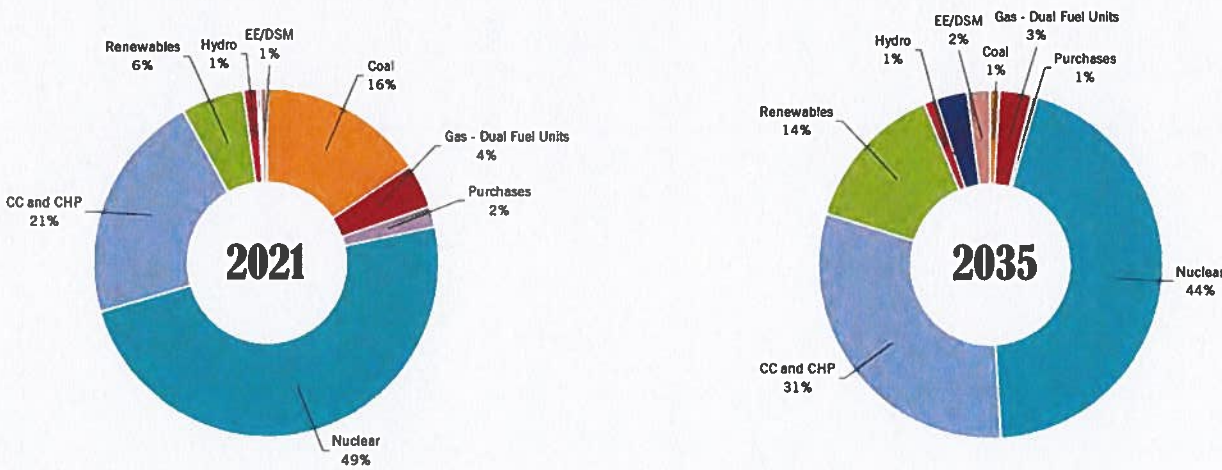


[4] All capacity based on winter ratings except Renewables and Energy Storage which are based on nameplate.

Corrected 11.06.2020

Figure 12-H represents the energy of both the DEC and DEP Base Cases with Carbon Policy over the IRP planning horizon. Due to the JDA, it is prudent to combine the energy of both utilities to develop a meaningful representation of energy for the Base Case with Carbon Policy. From 2021 to 2035, the figure shows that nuclear resources will continue to serve almost half of DEC and DEP's energy needs. Additionally, the figures display a substantial increase in the amount of energy served by carbon-free resources (solar, energy storage, solar plus storage, hydro and wind). Natural gas continues to remain an economical and reliable source of energy for the Companies, while the reliance on coal generation is reduced to 1%.

FIGURE 12-H
DEC AND DEP ENERGY OVER 15-YEAR STUDY PERIOD – BASE CASE WITH CARBON POLICY[5]



A detailed discussion of the assumptions, inputs and analytics used in the development of the Base Cases and other portfolios is contained in Appendix A. As noted, the further out in time planned additions or retirements are within the 2020 IRP, the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.

[5] All capacity based on winter ratings except renewables and energy storage which are based on nameplate.

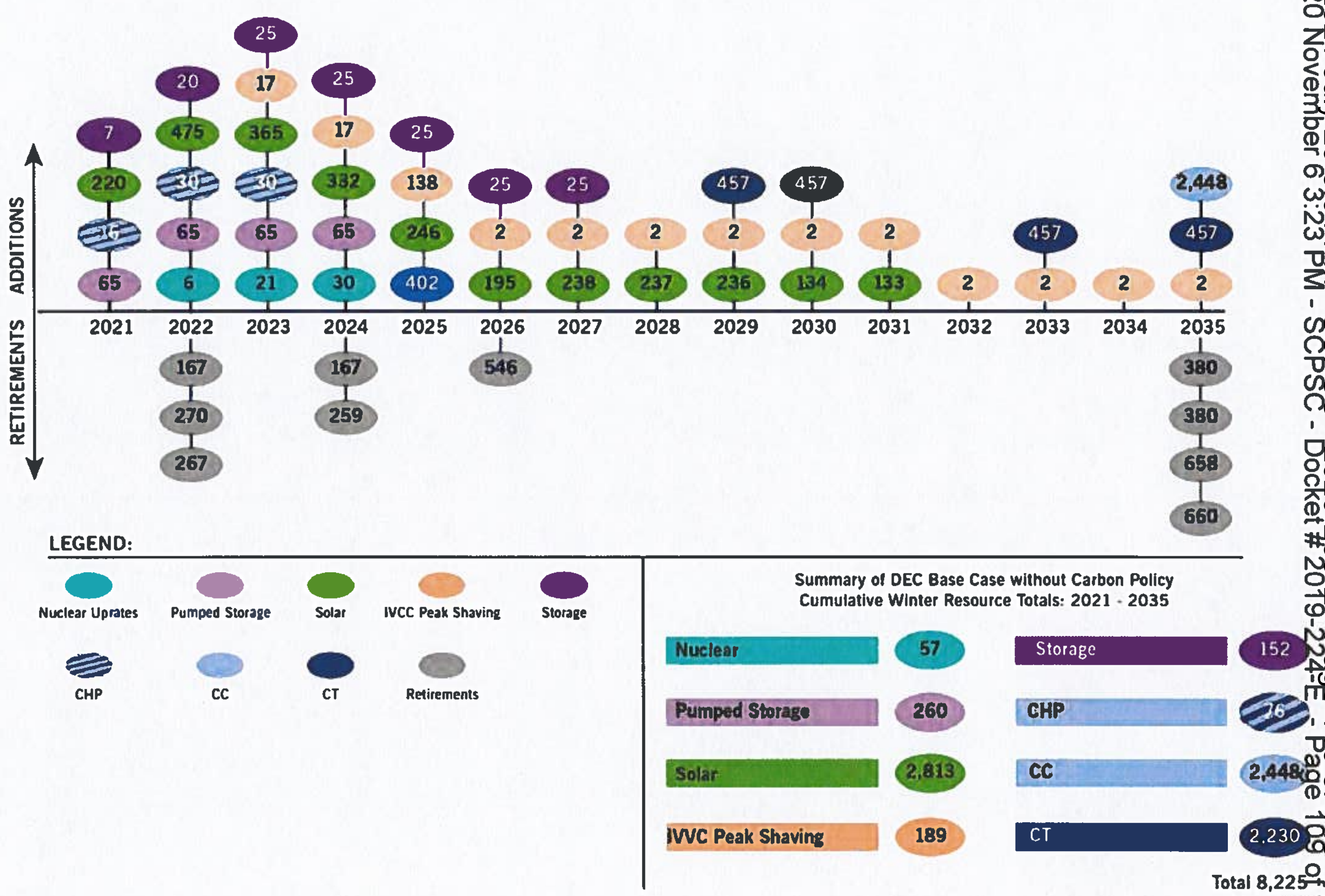
BASE CASE WITHOUT CARBON POLICY

While Duke Energy presents a base resource plan developed under a carbon constrained future, the Company also provides a Base Case without Carbon Policy expansion plan that reflects a future without CO_2 constraints. In DEC, this expansion plan is represented by Portfolio A or the Base Case without Carbon Policy. During the 15-year planning horizon, there is a significant shift toward CC technology as compared to the Base Case with Carbon Policy. Additionally, no incremental renewable resources were economically selected in this case.

A graphical presentation of the Winter Base Case without Carbon Policy resource plan is shown below in Figure 12-I. This figure provides annual incremental capacity additions to the DEC system by technology type for this case. Additionally, a summary of the total resources by technology is provided below the figure. Further details of the development of the Base Case without Carbon Policy may be found in Appendix A.

FIGURE 12-I

DEC BASE CASE WITHOUT CARBON POLICY ANNUAL ADDITIONS BY TECHNOLOGY



JOINT PLANNING CASE

As mentioned previously, a Joint Planning Case that explores the potential for DEC and DEP to share firm capacity between the Companies was also developed. The focus of this case is to illustrate the potential for the Utilities to collectively defer generation investment by utilizing each other's capacity when available and by jointly owning or purchasing new capacity additions. This case does not address the specific implementation methods or issues required to implement shared capacity.

Rather, this case illustrates the benefits of joint planning between DEC and DEP with the understanding that the actual execution of capacity sharing would require separate regulatory proceedings and approvals.

A discussion of the Joint Planning Case is provided in Appendix A.

Corrected 11.06.2020

13 DEC FIRST RESOURCE NEED

The IRP process provides a resource plan to most economically and reliably meet the projected load requirements and a reasonable reserve margin throughout the 15-year study period. In addition to load growth, planned unit retirements and expiring purchase power contracts contribute to the need for new generation resources.

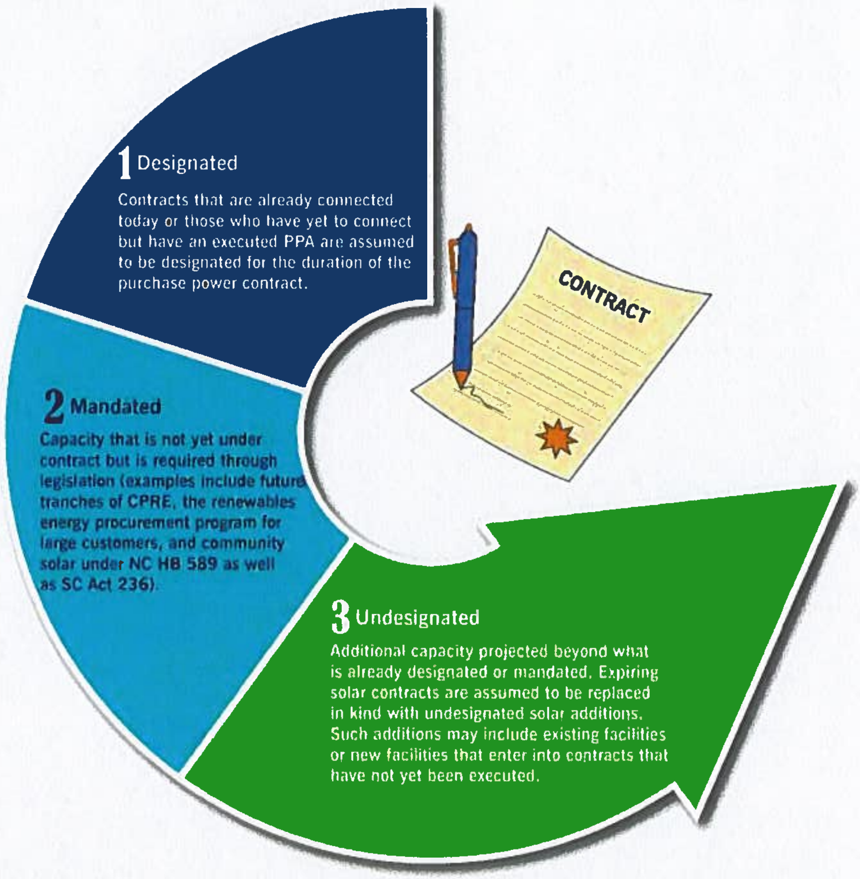
The resources used to meet the load requirements fall into two categories: Designated and Undesignated. Designated resources are those resources that are in service, projects that have been granted a Certificate of Public Convenience and Necessity (CPCN) or Certificate of Environmental Compatibility and Public Convenience and Necessity (CECPCN), smaller capacity additions that are a result of unit uprates that are in the Companies' planning budget, firm market purchases over the duration of the signed contract or DSM/EE programs.

Undesignated resources include purchase power contracts that have not yet been executed and projected resources in the IRP that do not have a CPCN or CECPCN granted,

Additionally, firm market purchases, which include wholesale contracts, including renewable contracts, are assumed to end at the end of the currently contracted period. There is no guarantee that the counterparty will choose to sell, or the Company will agree to purchase its capacity after the contracted timeframe. Beyond the contract period the seller may elect to retire the resource or sell the output to an entity other than the Company. As such, contracted resources are deemed designated only for the duration of their legally enforceable contract.

Further, solar renewable contracts are broken down into three categories: Designated, Mandated and Undesignated. As discussed in Chapter 5, the definitions of each bucket are below:

FIGURE 13-A
CATEGORIES OF CONTRACTS



Only designated and mandated resources are considered when determining the first need for purposes of the development of standard offer avoided capacity rates. As such, a list of these resources for DEC is below:

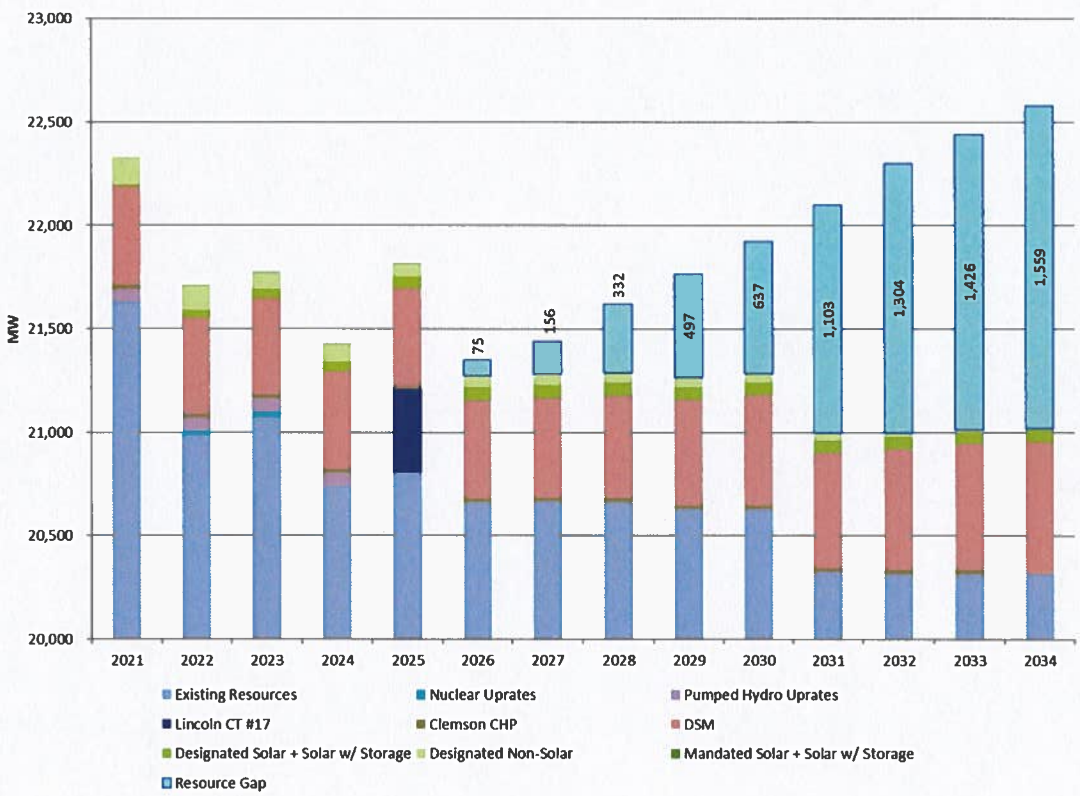
- Designated and mandated renewable resources
- Nuclear uprates
- Bad Creek runner uprates
- Clemson CHP project
- Lincoln CT project
- Designated wholesale contracts
- DSM/EE programs

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

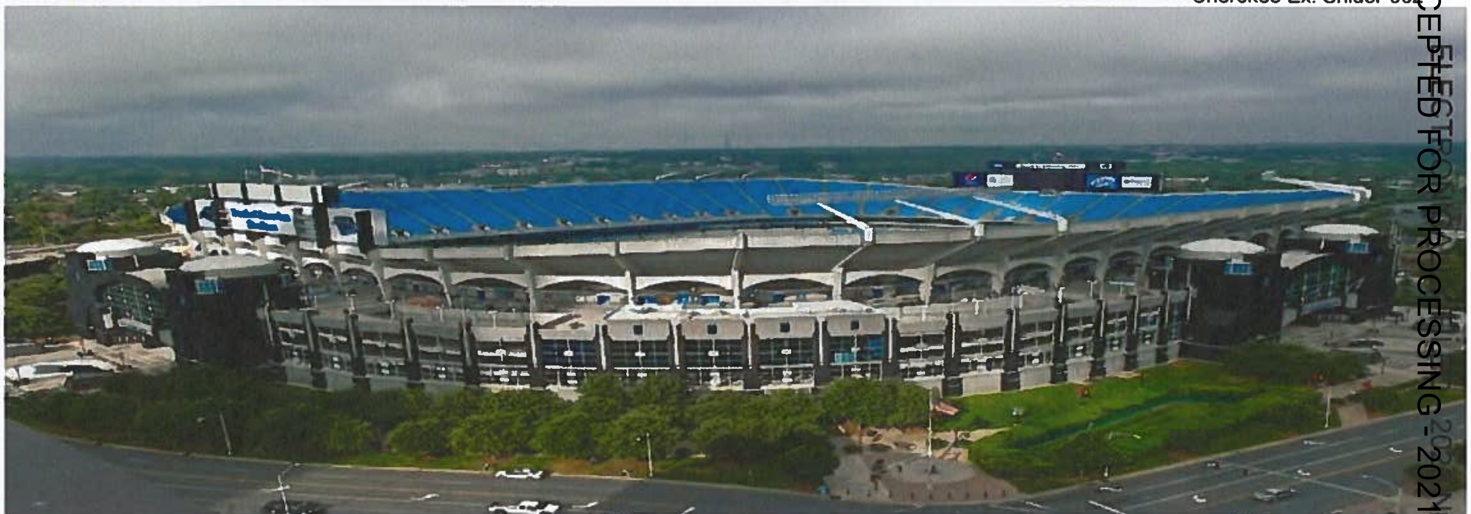
Including only the designated and mandated resources, Figure 13-B demonstrates the first need for DEC is in 2026. To the extent current contracts become executed and move from an undesignated to a designated resource, the timing of the first need will change accordingly.

FIGURE 13-B
LOAD RESOURCE BALANCE FOR DEC FIRST NEED



In the 2019 IRP, the first resource need for DEC was also determined to be in 2026. There has been no change to the first resource need in DEC.

Corrected 11.06.2020



14 SHORT-TERM ACTION PLAN

The Company's Short-Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, is summarized below:

ACCOMPLISHMENTS IN THE PAST YEAR

The following items were completed by DEP and DEC in the last year to support the development of the 2020 IRP:

COMPLETED STUDIES

As previously discussed in the Executive Summary, multiple studies have been completed in the previous year. The results of each of these studies were utilized in the development of the 2020 IRP. Table 14-A is a reproduction of the table presented in the Executive Summary.

DUKE ENERGY CAROLINAS

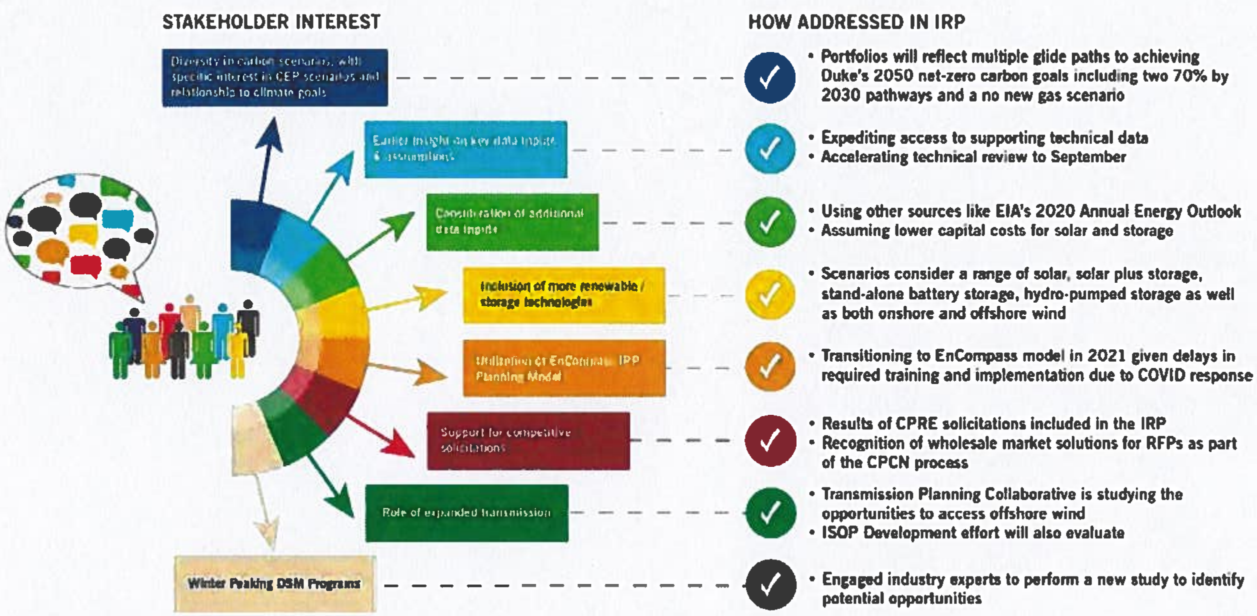
TABLE 14-A
COMPLETED STUDIES INFORMING THE 2020 IRP

STUDY	STUDY REQUIREMENTS
Economic Coal Retirements	• Analysis established the most economic coal unit retirement dates for the Base CO_2 and Base No CO_2 scenarios.
Earliest Practicable Coal Retirements	• Analysis established the earliest feasible coal unit retirement dates. Analysis set aside normal economic considerations and focused on procurement and construction timelines for replacement capacity in order to retire the coal units at the earliest attainable dates.
Resource Adequacy Study/ Reserve Margin Study	• Astrapé Consulting study evaluated reliability based on meeting the one day in ten years loss of load expectation (LOLE) metric.
Storage Effective Load Carrying Capability (ELCC) Study	• Astrapé Consulting study evaluated capacity value of storage under multiple conditions, including its contribution to winter peak and considerations with increasing levels of renewable penetration.
Energy Efficiency and Market Potential Study	• Nexant study evaluated market potential for energy efficiency and demand response initiatives.
Winter Specific DR and Rate Design Benchmarking Study	• Being conducted by Tierra Resource Consultants, Proctor Engineering Group, and Dunsky. Studies the integration of new rate designs and DSM technology with innovative program structures to drive winter peak focused reductions.

IMPLEMENTED COLLABORATIVE STAKEHOLDER ENGAGEMENT PROCESS

Duke Energy implemented an intentional process to collaborate with stakeholders to help shape the development of the 2020 IRP. Stakeholders in North Carolina and South Carolina provided recommendations in the areas of resource planning, carbon reduction, energy efficiency and demand response. 188 unique external stakeholder participants from across the Carolinas participated in this process. Figure 14-A provides a graphical representation of the intention of the stakeholder process, as presented in the Executive Summary.

FIGURE 14-A
STAKEHOLDER ENGAGEMENT



CONTINUED RELIANCE ON EE AND DSM RESOURCES

The Company is committed to continuing to grow the amount of EE and DSM resources utilized to meet customer growth. The following are the ways in which DEC will increase these resources:

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs spanning the residential, commercial, and industrial classes.

- Continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services, such as: (1) adding new or expanding existing programs to include additional measures drawing on insights gained through the updated Market Potential

Study, (2) program modifications to account for changing market conditions and new measurement and verification (M&V) results and (3) other EE research and development pilots.

- Continue to seek additional DSM programs employing both rate-enabled and traditional equipment-based measures that will specifically provide load reduction benefits during winter peak situations.

- The Company undertook a detailed study to specifically examine the potential for additional winter demand-side peak savings through innovative rates initiatives combined with advanced demand response and load shifting programs that were outside of the MPS scope. The Company envisions working with stakeholders in the upcoming months and beyond to investigate and deploy, subject to regulatory approval, additional cost-effective programs identified through this effort. Over time as new programs/rate designs are approved and become established, the Company will gain additional insights into customer participation rates and peak savings potential and will reflect such findings in future forecasts.

CONTINUED FOCUS ON RENEWABLE ENERGY RESOURCES

DEC is committed to the addition of significant renewable generation into its resource portfolio. Over the next five years DEC is projecting to grow its renewable portfolio from 1,099 MW to 2,778 MW. Supporting policy such as SC Act 236, SC Act 62, NC REPS and NC HB 589 have all contributed to DEC's aggressive plans to grow its renewable resources. DEC is committed to meeting its targets for the SC DER Program and under HB 589, DEC and DEP are responsible for procuring renewable energy and capacity through a competitive procurement program. DEC/DEP have completed two solicitations under CPRE, resulting in 1,049 MW of nameplate solar expected in DEC. Planning for the next phase of CPRE activities is underway. These activities will be done in a manner that allows the Companies to continue to reliably and cost-effectively serve customers' future energy needs. The Companies, under the competitive procurement program, are required to procure energy and capacity from renewable energy facilities in an aggregate amount of up to 2,660 MW through request for proposals. Note that the connection of other transition MW can act to replace the required CPRE capacity. DEC and DEP plan to jointly implement the CPRE Program across the NC and SC service territories.

For further details regarding DEC's plans regarding renewable energy, refer to Chapter 5, Appendix E, and Attachments I and II.

INTEGRATION OF BATTERY STORAGE ON SYSTEM

The Company has begun investing in grid-connected storage systems, with plans for additional multiple grid connected storage systems. These systems will be dispersed throughout its North and South Carolina service territories that will be located on property owned by the Company or leased from its customers. These deployments will allow for a more complete evaluation of potential benefits to the distribution, transmission and generation system, while also providing actual operation and maintenance cost impacts of batteries deployed at a significant scale. Also, as directed by the NCUC, the Company has been working with stakeholders to assess challenges and develop recommendations to address challenges related to retrofit of existing solar facilities with energy storage. A report on this matter is expected to be filed in September 2020. Finally, as noted in the table of studies above, the Company engaged Astrapé Consulting to perform a study to assess the incremental change in Effective Load Carrying Capability of battery storage as more batteries are added to the system. This report is further described in Chapter 6, Appendix H and Attachment IV.

IVVC IMPLEMENTATION AS PART OF THE GRID IMPROVEMENT PLAN

Lastly, Integrated Voltage/VAR Control (IVVC) is part of the proposed Duke Energy Carolinas Grid Improvement Plan (GIP) and involves the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid.

Once the GIP is approved, which is expected by 2022, the IVVC program is expected to be fully implemented in DEC by 2025. A detailed discussion of IVVC may be found in Appendix D.

CONTINUE TO FIND OPPORTUNITIES TO ENHANCE EXISTING CLEAN RESOURCES

DEC is committed to continually looking for opportunities to improve and enhance its existing resources. DEC has committed to the replacement of the runners on each of its four Bad Creek pumped storage units. Each replacement is expected to gain approximately 65 MW of capacity. The first replacement is projected to be in 2020, available for the 2021 winter peak. The remaining units will be replaced at the rate of one per year for availability in the winter peaks from 2022 to 2024.

Corrected 11.06.2020

DEC is expecting capacity uprates to its existing nuclear units at Oconee and Catawba, due to upcoming projects at those sites. The uprates total 57 MW and are projected to occur from 2021 to 2023.

ADDITION OF CLEAN NATURAL GAS RESOURCES[1]

- The Company continues to consider advanced technology combined cycle and combustion turbine units as excellent options for a diversified, reliable portfolio required to meet future customer demand. The improving efficiency and reliability of CCs coupled with the lower carbon content and continued trend of lower prices for natural gas make these resources economically attractive, as well as very effective at enabling significant carbon reductions through accelerated economic coal retirements. As older units on the DEC system are retired, CC and CT units continue to play an important role in the Company's future diverse resource portfolio.

  - An advanced combustion turbine unit began extended commissioning at the Lincoln CT Plant in North Carolina in 2020. Testing is currently underway. The Company will take care, custody, and control of the completed 402 MW unit in 2024.
  - A 15.7 MW Combined Heat and Power project is now operational at Clemson University. The CHP project was completed in November 2019 and is included as a designated resource in this IRP. Additionally, placeholders for two additional CHP facilities are included in 2021 and 2022. Duke Energy will continue to explore and work with potential customers with continuous large thermal loads on additional regulated CHP offers. Updates to this process will be included in future IRPs.

A summarization of the capacity resource changes for the Base Plans in the 2020 IRP is shown in Table 14-B below. Capacity retirements and additions are presented as incremental values in the year in which the change impacts the winter peak. The values shown for renewable resources, EE, DSM and IVVC represent cumulative totals.

[1] Capacities represent winter ratings.

Corrected 11.06.2020

TABLE 14-B
DEC SHORT-TERM ACTION PLAN

YEAR	RETIREMENTS (6)	ADDITIONS (3)	SOLAR (4)	SOLAR WITH STORAGE (5)	BIOMASS / HYDRO	CUMULATIVE EE	DSM	IVVC (7)
			RENEWABLE RESOURCES (CUMULATIVE NAMEPLATE MW)					
2021		9 MW Energy Storage 6 MW Nuclear Uprate 65 MW Bad Creek Upgrade 16 MW Clemson CHP	966	0	132	70	478	0
2022	704 MW Allen 2-4	20 MW Energy Storage 21 MW Nuclear Uprates 65 MW Bad Creek Upgrade 30 MW CHP	1,327	115 w/ 25 Storage	118	129	467	0
2023		25 MW Energy Storage 30 MW Nuclear Uprates 65 MW Bad Creek Upgrade 30 MW CHP	1,673	134 w/ 30 Storage	81	183	468	17
2024	426 MW Allen 1 and 5	25 MW Energy Storage 65 MW Bad Creek Upgrade	1,976	163 w/ 37 Storage	81	233	470	34
2025		402 MW Lincoln CT Project 25 MW Energy Storage	2,268	192 w/ 45 Storage	59	303	473	173

(1) Capacities shown in winter ratings unless otherwise noted.
(2) Dates represent when the project impacts the winter peak.
(3) Energy storage is grid-tied storage and represents total usable MW.
(4) Capacity is shown in nameplate ratings and does not include solar coupled with energy storage.
(5) Solar coupled with storage; storage only charged from solar.
(6) Retirement dates reflect 'most economical' dates from the Coal Retirement Analysis.
(7) Integrated Volt Var Control represents cumulative impacts.

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

CONTINUE WITH PLAN FOR SUBSEQUENT LICENSE RENEWAL OF EXISTING NUCLEAR UNITS

In September 2019, Duke Energy announced its intent to pursue SLR for all eleven nuclear units in the operating fleet. The Oconee SLR application will be submitted first, in 2021. An SLR application takes approximately three years to prepare and approximately two years to be reviewed and approved. As information, Oconee's current licenses are set to expire in 2034 and 2035.

Continued Transition Toward Integrated System and Operations Planning:

As explained further in Chapter 15, the concept of ISOP remains on the path as described in the 2019 IRP filed in NC and SC. The Company continues to view this effort as an important and necessary evolution in electric utility planning processes. The Company remains committed to the goal of implementing the basic elements of ISOP in the 2022 IRPs for the Carolinas. This timeline is based on the Company's perspective that declining costs of distributed resources, including energy storage and advanced demand response options will increasingly create opportunities late in this decade and beyond to defer or potentially even avoid traditional "wires" upgrades and, in some cases, help to offset needs for building generation resources.

CONTINUED COMMITMENT TO MEETING THE COMPANY'S CARBON PLAN

As discussed throughout this IRP document, DEC is committed to meeting Duke Energy Corporation's Carbon Plan. All six of the key portfolios outlined in the Executive Summary keep Duke Energy on a trajectory to meet its near-term enterprise carbon reduction goal of at least 50% by 2030, and long-term goal of net-zero by 2050. See Chapter 16 for additional discussion on the net-zero carbon goal. As part of Duke Energy's long-standing commitment to carbon reductions, older coal and CT units have been retired and replaced with cleaner renewable energy resources and advanced CC and CT units. The overall effort includes the following elements:

- As of April 2015, Duke Energy Carolinas has no remaining older, un-scrubbed coal units in operation.[2]

[2] The ultimate timing of unit retirements can be influenced by factors changing the economics of continued unit operations. Such factors include changes in relative fuel prices, operations and maintenance costs and the costs associated with

Corrected 11.06.2020

DUKE ENERGY CAROLINAS

- To date, DEC has retired approximately 1,700 MW of older coal generation since 2011.

- Allen unit retirements in YE2021 and YE2023 and the associated new South Point switchyard, which is necessary to allow for the retirement of all five Allen units, will bring economic value to customers and further the clean energy goals held by the Company and stakeholders. As with all unit retirement dates in the IRP, this is not a commitment to retire the Allen units on this timeline but rather contains the Company's most recent estimate of retirement economics at the time of this filing. Official retirement will require final management approval with final retirement dates contingent upon the finalization of the supporting switchyard project and other operational considerations. With the potential retirement of Allen Steam Station on the horizon, it is noteworthy that the facility has provided reliable energy to the Carolinas for over 60 years.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with existing and potential environmental regulations such as Mercury Air Toxics Standard (MATS), the Coal Combustion Residuals (CCR) rule, the Cross-State Air Pollution Rule (CSAPR), and any future federal or state carbon reduction policies.

WHOLESALE

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy balancing authority area.

- Over the next five years, DEC has a very small amount of contracts that expire under the current contract terms. The Company will determine the feasibility of obtaining additional purchased power arrangements in the future to economically meet customer demand.

REGULATORY

- Continue to monitor energy-related statutory and regulatory activities.
- Continue to examine the benefits of joint capacity planning and pursue appropriate regulatory actions.

compliance of evolving environmental regulations. As such, unit retirement schedules are expected to change over time as market conditions change.

DEC REQUEST FOR PROPOSAL (RFP) ACTIVITY

SUPPLY-SIDE RFP ACTIVITY

Outside of renewable solicitations, no supply-side RFPs have been issued since the filing of DEC's last IRP.

COMPETITIVE PROCUREMENT OF RENEWABLE ENERGY (CPRE)

Pursuant to N.C. Gen. Stat. § 62-110.8, DEC has completed the first RFP solicitation under the Competitive Procurement of Renewable Energy Program and is currently in the contracting phase for the second RFP. In summary, the final results from Tranche 1 and the initial results from Tranche 2 appear to have been successful, procuring approximately 1,049 MW of resources at prices below administratively-established avoided costs, pending Tranche 2 on-going contract negotiations. Details concerning the CPRE program can be found in the annual CPRE Program Plan filing, which is Attachment II to this document.

15 INTEGRATED SYSTEM & OPERATIONS PLANNING (ISOP)

The concept of ISOP remains on the path as described in the 2019 IRP filed in NC and SC. The Company continues to view this effort as an important and necessary evolution in electric utility planning processes to address the trends in technology development, declining cost projections for energy storage and renewable resources, and customer adoption of electric demand modifying resources such as roof-top solar and electric vehicles (EVs). The anticipated growth of Distributed Energy Resources (DERs) necessitates moving beyond the traditional distribution and transmission planning assumption of one-way power flows on the distribution system and analysis based on limited snapshots of peak or minimum system conditions. As the grid becomes more dynamic, analysis of the distribution and transmission systems will need to account for increasing variability of generation and two-way power flows on the distribution system, which requires significant changes to modeling inputs and tools. The Company remains committed to the goal of implementing the basic elements of ISOP in the 2022 IRPs for the Carolinas. This timeline is based on the Company's perspective that declining costs of distributed resources, including energy storage and advanced demand response options will increasingly create opportunities late in this decade and beyond to defer or potentially even avoid some traditional "wires" upgrades and, in some cases, help to offset needs for building generation resources.

The advancements in planning tools through the ISOP initiative also open new possibilities for analysis to help identify transmission and distribution infrastructure opportunities from a more holistic perspective. In the current regulatory paradigm, utilities provide first come, first serve access to resource developers and utility participants that request system interconnections where their projects seem best suited. This paradigm tends to result in the utility systems evolving incrementally based

Corrected 11.06.2020

on the requests they receive, in the order received, in contrast with a system plan that could be developed reflecting the desired energy resource mix over the longer term. Over time, there may be the opportunity to evolve to a longer-term grid planning approach as contemplated here, but it is important to recognize that this type of transition would affect many stakeholders and would require constructive regulatory support to consider these changes. These ideas reflect some of the longer-term strategic concepts that are being considered in the development of the new ISOP advanced planning tools and processes.

DISTRIBUTION CIRCUIT LEVEL FORECASTING

Historically, distribution planners have used historical peak snapshots along with an expected growth factor to assess circuit capacity needs. To assess the potential for non-traditional solutions such as energy storage or other DERs, hourly time-series forecasts are needed at the circuit level to analyze the expected load profile, including how it could change over time as a function of residential, commercial or industrial growth, or adoption of net load modifiers such as energy efficiency, rooftop solar, and electric vehicles. This effort involves a significant time and resource commitment to gather the necessary input data and build the forecasting models required to support this extensive level of granular forecasting. Over the past year, the Company has developed models to enable derivation of hourly forecasts for the distribution circuits in the Carolinas covering a ten-year horizon. These models are currently in a cycle of validation and refinement, with the expectation to progressively roll the forecasts out to distribution planners throughout 2021 to support testing of the Advanced Distribution Planning toolset.

ADVANCED DISTRIBUTION PLANNING (ADP)

As noted above, distribution planners have traditionally analyzed historical peak snapshots. More dynamic grid conditions driven by distributed resources and circuit switching capability require more complex hourly power flow analysis to study the effects of DERs and assess the effectiveness of both traditional and non-traditional solutions (or combinations of solutions). Duke has continued its work with CYME, an industry leader in distribution modeling, to develop an ADP tool capable of performing these detailed analyses and supporting evaluation of both traditional and non-traditional solutions on the system. The development and testing effort over the past year has largely focused on automation and integration to make complex evaluation processes more efficient for the planners. The project remains on-track for the basic ADP functionality to be progressively rolled out to DEC and DEP

Corrected 11.06.2020

distribution planners for testing and validation beginning in late 2020 and throughout 2021. Subsequent development efforts will focus on broadening the data available to planners, improving the efficiency of the modeling systems through integration and automation, and adding more robust capabilities such as multi-circuit analysis and combinations of traditional and non-traditional solutions, etc.

The new functionality of the ADP toolset will enable planners to evaluate DERs (including energy storage) as a potential solution for capacity needs and identify the most likely hourly patterns where potential new DERs would be needed to address local issues. These DER profiles could then be included as an input to transmission and generation planning processes to further assess potential value at the transmission and bulk generation levels. The growth in the scope and volume of the detailed data required to perform these new integrated planning studies is driving the need for much more coordination between planning groups and integration between the respective models across distribution, transmission, and generation planning.

While the ADP development effort is underway, the Company has also worked on developing screening processes to efficiently identify distribution upgrade needs that could potentially be deferred with non-traditional solutions. This process provides an opportunity to study a variety of potential energy storage use cases and better understand the steps that would be needed to perform a more detailed analysis for any candidates of interest that did appear. In this initial analysis of existing traditional distribution projects, 3% of the population was found to be suitable for further study, which is ongoing. It should be noted that the screening process at this stage uses relatively generous assumptions to avoid screening out a potential high value candidate prior to gaining experience and refining the process through detailed studies.

As part of the Company's broader industry engagements, the ISOP and ADP teams participated in a multi-utility collaborative study in the first half of 2020 led by the Smart Electric Power Alliance (SEPA) on Integrated Distribution Planning. The feedback the Company received in this forum along with review of SEPA's draft publication which should be released in the near future increases the Company's confidence in its approach to ADP.

Corrected 11.06.2020

INTEGRATION WITH TRANSMISSION PLANNING PROCESSES

To complement existing NERC Standard and FERC Order compliance-based Transmission Planning processes, the Company is developing new modeling capabilities for examining long term transmission needs and DER integration on the grid at an hourly granularity using some of the advanced features of an industry standard third-party DC power flow model. Accomplishing this additional level of detailed analysis requires extensive development work to integrate models and data sources and allow for hourly power flow analysis to complement the industry standard third-party AC power flow model used for transmission planning today. The DC power flow analysis is being developed for screening over broad time periods to help planners identify specific time periods and operating conditions that may warrant more detailed AC power flow analysis using the conventional transmission planning tools.

These enhanced new transmission modeling tools and processes will be used to support comprehensive assessments of transmission needs as the system evolves with coal plant retirements and significant growth of distributed energy resources. These studies, in concert with regional and interregional planning studies, will help planners find ways to optimize the use of existing grid capabilities and plan cost effective options to upgrade grid capabilities needed to support integration of the array of new resources necessary to meet the clean energy planning objectives. These new tools being developed and deployed as part of the ISOP program are critical to answering important questions about how the utility will integrate diverse energy resources to reliably serve customers in the future and how the utility will balance economic priorities in this transition.

Over the last year, the Company has also worked on developing screening processes to efficiently identify transmission upgrade needs that could potentially be deferred with non-traditional solutions. Going through this process also helps to build shared understanding among the team regarding potential energy storage use cases and the opportunities and challenges of adding value through multiple use cases. In this initial screening analysis of current transmission projects in early development, none were found to be both cost-effective and technically viable. While this result was expected in light of near-term energy storage costs, it should not be considered indicative of long-term opportunities. As noted in Chapter 6, the cost of energy storage is projected to decline by about 50% by 2030, which would significantly improve opportunities for non-traditional solutions.

ENHANCED RESOURCE PLANNING AND ISOP OPTIMIZATION

To successfully examine pathways to meet clean energy objectives in the manner envisioned in ISOP, it is critical to consider the mix of both centralized and distributed energy supply resources in use over the planning period and examine the interactions of the energy resources with the delivery systems to ensure that energy can be efficiently managed and delivered on the grid. Creation of this collaborative planning process with Distribution and Transmission Planning also relies on complementary development efforts in the Resource Planning area to address broader planning challenges. In Resource Planning, the capacity expansion model and hourly production cost model provide planners the tools they need to explore a wide range of resource portfolios while performing optimization and detailed production cost studies to fully understand the behavior and costs of the system. To meet the rigors of the new planning challenges, the modeling tools and processes also need to allow planners to examine carbon compliance regimes, operational impacts of increasing levels of variable resources, utilization of different types of storage, applications of resources to address ancillary system needs and many other facets of future operations.

In 2020, the Company elected to move forward with deploying the EnCompass suite of resource planning models from Anchor Power Solutions to address these enhanced planning needs. The plans to shift to the new model were based, in part, on feedback from stakeholders as part of the IRP development process. The ISOP and Resource Planning teams are also working with the Fuels and System Optimization (FSO) Analytics team to study the effects of perfect foresight on production cost modeling results and explore the benefits of including their sub-hourly modeling and stochastic analysis to further refine modeling results for fast responding generation resources and storage to meet operational needs in the future with higher levels of variable renewable generation. The issue of "perfect foresight" in production cost modeling is addressed in more detail in Chapter 16.

Transitions to new models and functionality require time and substantial testing and integration efforts, which are currently underway with a goal of formally switching to EnCompass during the fourth quarter of 2020. As the Resource Planning team gains familiarity with these new tools, ISOP will also be assisting with development of new planning processes to support the collaboration between Resource Planning and the other planning disciplines and working toward integrating the new processes being developed in each of these areas. These integration efforts will involve development to support integration of modeling systems and also harmonizing inputs and coordinating

Corrected 11.06.2020

planning cycles between the planning disciplines to allow for better flow of information and data required to produce the integrated planning results.

ISOP STAKEHOLDER ENGAGEMENT

Outreach has been and remains an important part of the ISOP effort. The Company's ISOP team has been gathering input from other utilities, national labs, EPRI, consultants, and academic groups to inform the Company's vision and work-scope to better address the challenges of modeling renewables and energy storage at both the distribution and transmission levels. There is also interest in these ISOP development efforts from the Company's regulators and customers, as well as environmental advocates, business interest groups, and other stakeholders. Duke initiated a series of stakeholder engagements in late 2019 to help address these interests, supported by ICF, an industry-leading consultant in advanced integrated planning and regulatory engagement.

The first stakeholder workshop in Raleigh on December 10, 2019 was well attended and provided a face-to-face opportunity for stakeholders to gain some insights from ICF on how integrated planning is unfolding across the industry, learn more about ISOP's development plans, and hear about some of the development work streams underway at that time. It also provided Duke participants with an opportunity to hear input and feedback from several of the Company's stakeholders and to engage in discussions on what is important to them and to the participants who attended. Several stakeholders constituting a diverse set of viewpoints participated in two panel sessions that helped ensure the workshop communication and information transfer was multidirectional. Considering the complexity of the subject matter and the initial nature of stakeholder engagement, it was a very successful kick-off event.

The ISOP/ICF team subsequently hosted two stakeholder webinar sessions on January 30, 2020 and March 20, 2020 to continue discussions on the Company's progress and introduce additional industry and ISOP topics for review and discussion with stakeholders. These exchanges provided productive opportunities for stakeholder feedback and discussions and helped support Duke's focus and priorities for future stakeholder sessions, as well as the information and services that will ultimately be shared as a result of ISOP efforts. All of the materials shared in these sessions and recordings of the sessions themselves are posted on the ISOP Information Portal[1] online for participants and other interested parties to review.

[1] https://www.duke-energy.com/our-company/isop.

As part of the broader ISOP stakeholder engagement effort, the Company has collaborated with North Carolina Electric Membership Corporation (NCEMC) to exchange ideas related to ISOP. As an extension of this collaboration, NCEMC has been working with the Company to improve coordination between the customer's Distribution Operator and the Company's Transmission Operator, and the two parties have developed a plan for coordinated testing of the wholesale customer's advanced DR and DER program for reliability coordination and local loading relief effects at the distribution and transmission levels. The parties have agreed to continue this collaboration beyond these initial steps as the ISOP process evolves to ensure that planning and operations are aligned. The Company will pursue additional ISOP-related interactions with other Distribution Operators within the balancing areas as future opportunities are identified through the normal course of outreach to these stakeholders.

ISOP hosted its second stakeholder workshop – a "Virtual Forum" due to pandemic safety concerns – on August 21, 2020 to update stakeholders on the continuing progress of the ISOP program and engage in more dialogue relating to what stakeholders consider important. A group of stakeholders presented on their desired outcomes from ISOP, which helped frame the different types of impact that ISOP could ultimately have, as well as further educate Duke participants on key issues that may be taken into consideration as the ISOP development process continues to unfold. All of the materials shared in the final session and recordings of the presentations will also be posted on the ISOP Information Portal online for participants and other interested parties to review. ICF will summarize the overall stakeholder engagement effort in a final, public-facing report in the fourth quarter of 2020.

The Company plans to provide future updates to stakeholders regarding the ISOP initiative through virtual webinars as the Company's development effort progresses toward the initial introduction of ISOP processes in the 2022 IRP. To help with managing expectations, it is worth reiterating that technology costs, supply chain, regulatory policy, and other challenges may require five to ten years for non-traditional solutions to become competitive options on a regular basis. Given the lead time to implement and refine complex new analytical processes as well as the importance of these efforts to support an affordable and reliable transition to net-zero carbon, it is critical to continue investing in this important work.

16 SUSTAINING THE TRAJECTORY TO REACH TO NET-ZERO

This chapter discusses, in qualitative terms, key elements needed to accelerate CO_2 reductions and sustain a trajectory to the Company's net-zero carbon goal, some which are at or beyond the fifteen-year horizon of the IRP. In 2019, the Company announced a corporate commitment to reduce CO_2 emissions from power generation by at least 50 percent from 2005 levels by 2030, and to achieve net-zero by 2050. This shared goal is important to many of the Company's customers and communities, many of whom have also adopted their own clean energy initiatives. The Company has already made significant progress by reducing CO_2 emissions by 39% across its entire seven-state territory since 2005, well ahead of the industry average of 33%.

The Company also released the Duke Energy 2020 Climate Report in April 2020, which offered insights into the complexities and opportunities ahead and provided an enterprise-level scenario analysis with an illustrative path to net-zero. Among the key elements identified for the path to net-zero carbon were:

- Investments in the grid to allow significant growth in renewables and energy storage, including a transition to intelligent grid controls to support growth of distributed resources and increased customer options,

- Advancement of planning tools and integration of planning processes to address the increasingly complex and dynamic grid and leverage the potential of energy storage and innovative customer programs and rate designs (see Chapter 15),

- Advancements in demand side management and energy efficiency (see Chapter 4 and Appendix D),

Corrected 11.06.2020

- Natural gas as a component of near-term opportunities for lower cost accelerated coal retirements,
- Advancement of Zero Emitting Load Following Resource (ZELFR) technologies, to be ready for commercial operation by the mid-2030s,
- Continued operation of the existing nuclear fleet,
- Consideration of pace and trajectory of CO_2 reduction relative to impacts on affordability and reliability for customers,
- Supportive policies to allow increased pace of interconnection and accelerated transmission and distribution infrastructure, and,
- Supportive policies for CO_2 reduction.

Support for a number of these elements has been evident in a variety of the Company's stakeholder engagement efforts. Key elements above that have been addressed in other Chapters of this IRP are referenced accordingly, while others are addressed below.

TRANSFORMATION OF THE ELECTRIC GRID

The nation's electric delivery system design is more than 100 years old, and much of the equipment installed across the country has been in place for decades. Since conventional generation resources have historically benefitted from economies of scale, the electric grid was designed to transport electricity from large centralized generation plants to customers. These centralized plants provided critical voltage support, and the downstream distribution system was designed for a one-way power flow from the transmission level down to the customer. This fundamental infrastructure is still the basis for the grid today, which has limitations in its capability to seamlessly integrate large amounts of renewable energy sources or fully leverage distributed resources, such as batteries at the local circuit level.

As the Company continues its shift away from traditional coal-fired generation sources in the Carolinas, the transmission and distribution grid infrastructure and associated control systems will need to transition to a more highly networked system capable of dynamically handling two-way power flows resulting from broader deployment of distributed energy resources and supporting new ways in which customers will consume energy. As a transformation to cleaner energy is occurring, customers' energy utilization is also expected to evolve in different ways through advancements in new customer options and movement toward electrification of transportation and other sectors of the economy.

These trends coupled with significant increased utilization of variable renewable energy sources and retirement of resources that have historically provided critical voltage support and full dispatchability over long durations help highlight the challenges ahead for utilities to identify and develop the grid infrastructure and interconnected resources that can efficiently and reliably serve customers' energy needs while also supporting CO_2 reductions.

Some of these emerging needs are already impacting the Company's planners and operators, but the transition needed to achieve carbon neutrality will introduce much more significant challenges. The Company has been proactive in identifying these trends and taking steps to develop the needed grid capabilities and in adapting our planning processes with the Integrated System and Operations Planning (ISOP) initiative. These initiatives recognize the traditional one-way power flow capacity planning approach must be adjusted to reflect the need for flexible and advanced control systems to handle a much more dynamic grid. Keeping the grid running reliably is a balancing act, where the amount of power put into the grid must equal the amount taken out in real time. The utility's control systems continuously ramp central station generating units up or down to meet electric demand of the customers it serves. With the growing contribution of renewable energy sources, which have variable output from minute to minute, this balance becomes increasingly challenging to maintain. In a similar way, as distributed generation becomes more prevalent on circuits, it becomes necessary to introduce localized intelligent control systems that can also contribute at the system level.

Today, the Company is working to build these capabilities through its grid investments that begin to lay a critical foundation for embracing large amounts of private renewable energy. These investments include:

1) Self-optimizing grid (SOG) which fundamentally redesigns key portions of the distribution system and transforms it into a dynamic, smart-thinking, self-healing grid that can accommodate two-way power flows generated by the increased utilization of distributed resources.

2) Integrated Volt-Var Control (IVVC) will allow the Company to more closely monitor and control the voltage on the distribution system and more effectively manage voltage fluctuations due to intermittency of renewable energy sources, while enabling energy and peak demand savings to our customers over time.

3) Distribution automation, which leverages modern and often remotely operated equipment that supports continuous system health monitoring.

4) Transmission system intelligence, which improves system device communication capabilities enabling better protection, monitoring and optimization of system health and equipment.

5) Advanced Metering Infrastructure (AMI) that enables net metering while also providing the data necessary to better understand customer usage and develop enhanced customer programs.

6) Advanced Distribution Planning (ADP) tools and analytic processes that will help enable the integrated system operations planning process needed to optimize future investment decisions in the distribution system as next-generation technologies emerge and advance to become cost-competitive relative to traditional distribution investments.

7) Battery storage at the substation level can help with reliability and potentially balance and optimize load during peaks as well as low renewable periods to maximize carbon free generation on a circuit level.

These represent foundational, no-regrets investments that equip the grid with capabilities and tools to successfully transition from legacy one-way circuits to modern two-way power flow circuits. This foundation enables the legacy electric grid to better support carbon reductions by allowing increased integration of distributed resources and advancement of programs to leverage flexible demand, while also enhancing circuit resilience to withstand and recover from extreme weather events.

Leveraging the ISOP process and the Advanced Distribution Planning (ADP) tool for analysis and prioritization will be key for making sound economic choices at the circuit level complementing transmission and generation capacity needs. There are opportunities to advance a greener circuit design process to combine and coordinate with customer-facing programs to enhance peak demand control of customer loads, enable DERs, and support electric vehicle growth. Managing cost drivers for maintaining the grid while meeting carbon reduction goals is a key value opportunity.

Embracing demand response through advanced customer options with load-shaping programs is an essential element in the overall effort to reach the shared interest goal of net-zero CO_2 emissions, making it easier for customers to manage their energy usage and carbon footprint while supporting a greener grid and power supply. To accomplish this, the local grid must become more responsive, requiring intelligent, robust controls and customer programs that help to optimize DER integration. This vision would include supporting customer programs for managing and coordinating home and fleet EV battery charging. Managed EV charging is an emerging and valuable tool to support lower carbon emissions by reducing existing load peaks and eliminating risks from new ones, such as the transportation sector.

Over time, applying a holistic, customer-focused design approach combining advanced circuit monitoring and control capabilities with innovative customer programs and rate designs will further reduce customer outage impacts while also enabling a more sustainable, efficient and greener grid. As new opportunities are identified, the ISOP process will ensure balanced choices that manage cost, while growing the DER portfolio and enabling customers with clean, renewable energy options.

BUILDING ON SUCCESS AND SUSTAINING THE TRAJECTORY TO REACH NET-ZERO

The Company has made strong progress reducing CO_2 emissions since 2005, achieving a 38% reduction across the combined DEC/DEP systems between 2005 and 2019 – well ahead of the industry average of 33%. This progress is notable considering that Duke Energy's carbon intensity in the Carolinas was already low in 2005 relative to the industry average due to the significant contribution of emissions-free nuclear energy. Over this timeframe, the Company has retired nearly 4 GW of coal resources in the Carolinas. These retirements were primarily enabled by replacement with modern efficient natural gas combined cycle generation, which reduces emissions by more than 50% for each MWh replaced while maintaining affordability and reliability for customers. The replacement of coal with gas resources has been the single largest factor contributing to the Company's success in reducing the combined DEC/DEP CO_2 emissions. The Company has also interconnected nearly 4GW of renewable generation over the past decade, supporting the Carolinas emergence as a national leader in solar capacity. Comparing the level of generation from these renewables in 2019 to average carbon emissions of dispatchable resources that would have otherwise

Corrected 11.06.2020

been used to balance customer demand, the renewable resources contributed approximately 11% of the 38% carbon reduction.

While the contribution to carbon reduction from renewables is smaller than that of natural gas, both resources play important roles in the overall reduction of 38%. There is a learning opportunity in this experience. In adding roughly equivalent amounts of natural gas combined cycle and solar generation, the ability of natural gas combined cycle generation to displace the coal generation at much higher capacity factors drove the significantly larger portion of the 38% carbon reduction while keeping customer costs low. Finding the right balance between accelerating the pace of emissions reductions and new technology deployment while maintaining affordability for customers will continue to be an important consideration moving forward.

Although natural gas has and could continue to play a key role in accelerating coal retirements cost effectively[1], that role is expected to gradually change over the life of the natural gas assets, as noted in the Company's 2020 Climate Report. During the IRP Stakeholder process, some stakeholders voiced concerns about the risks of new gas generation assets becoming stranded. This was addressed by running a stress test case with an assumption of a shortened twenty-five-year life for natural gas units. With this assumption, the capacity expansion model continued to select natural gas units for the Base cases. There is also the possibility that generation, transport, and utilization of green hydrogen could become economic and extend the life of gas assets while reducing or eliminating carbon emissions. Blends of up to 10% hydrogen should be possible with the existing gas fleet with minimal tuning required, and new gas turbines are being designed for much higher capabilities of up to 100% hydrogen without modifications. The Company is partnering with Siemens and Clemson University on a proposal for a DOE study on the use of hydrogen for energy storage as a first step in exploring these opportunities.

PACE OF ADOPTION AND BENEFITS OF RESOURCE DIVERSITY

Moving forward, it will be important to consider both the pace of adoption and the benefits of portfolio diversity to mitigate risks of being too dependent on a small group of technologies. The graph below illustrates the benefits of adding offshore wind and, to a lesser extent onshore wind to improve the contribution of renewables to winter peak demand, which drives the resource planning process. For these emerging technologies, a measured pace of adoption can simultaneously promote technology

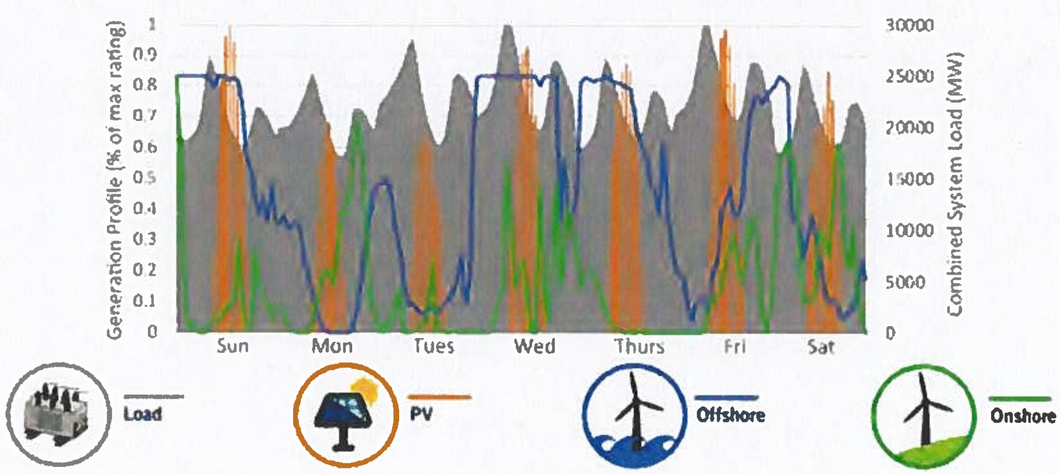
[1] Getting to Zero Carbon Emissions in the Electric Power Sector, Joule, Dec. 19, 2018.

Corrected 11.06.2020

development and operational experience with new technologies, while also allowing customers to benefit from price declines over time. Also, as shown by the NREL Phase 1 Carbon Free Resource study, as more of a given type of renewable resource is added to the system, the energy benefit diminishes, which reinforces the benefits of favoring diversity among renewable resources as the level of installed renewables increases. The Company continues to work with NREL and stakeholders to better understand the potential impacts of high renewable portfolios as well as the benefits of improving the diversity of renewables by evaluating onshore and offshore wind. For this reason, the Company has included both onshore and offshore wind in this IRP, even though there are substantial technical and policy issues that would need to be addressed to make such a pathway plausible.

The Company continues to investigate these opportunities through participation with the NC Clean Energy Plan modeling working group and the NREL Phase 2 Carbon Free Resource study. Additionally, the Company has partnered with NREL and a number of other National Laboratories to submit a DOE proposal for an extensive study of Reliability and Resilience in Near-Future Power Systems.

FIGURE 16-A
CAROLINAS RENEWABLE ENERGY PROFILES



DUKE ENERGY CAROLINAS

NEED FOR ENHANCEMENTS IN MODELING ASSUMPTIONS AND TECHNIQUES

One of the key uncertainties of these 2020 Carolinas modeling efforts is the feasibility of onshore wind. Aside from the policy barriers, there is a significant need for meteorological towers to collect wind speed history in key areas across the Carolinas to gain confidence in predicted capacity factors. The Carolinas onshore wind profiles used in this IRP were provided by a third party and are likely not based on wind speeds measured near the expected hub heights. The Company is working to improve the quality of Carolinas onshore wind profiles for use in future IRPs.

Beyond the current work with NREL and the NC Clean Energy Plan, there are a number of issues that require detailed modeling and analysis to better understand the operational risks associated with significantly increased reliance on energy storage for meeting capacity needs coupled with reliance on very high levels of renewable resources for energy. First, traditional production cost modeling, used in key processes ranging from IRP development to the unit commitment planning that drives actual daily operations, has "perfect foresight" of system load, renewable output, unplanned outages and derates, etc. While this is an unrealistic assumption, with the moderate levels of renewables and relatively low levels of energy storage today, the impact of the perfect foresight is small due to the abundance of dispatchable resources that do not require the precise timing that short duration energy storage does (for both charging and discharging) to ensure that the highest load hours are fully covered.

With some portfolios in this IRP containing approximately four times the present level of renewables and storage and a much smaller proportion of long duration dispatchable resources, new production cost modeling techniques and operational protocols will need to be developed to properly represent and actively manage the risks related to forecast error and imperfect foresight. Second, while there is considerable experience with managing the impacts of extreme weather events on the existing fleet with its current abundance of flexible, long duration dispatchable resources, there is no experience in the US or abroad with the scale of dependence on short duration energy storage represented by the 70% reduction and no new gas portfolios of this IRP. These issues require new modeling techniques to assess and manage the challenges to ensure operational implications of the transition are well understood.

Notably, the Company is participating with Duke University and other academic researchers and industry reviewers in a DOE project as part of the ARPA-E PERFORM program (Performance-based

Energy Resource Feedback, Optimization, and Risk Management). This is a three-year study effort just getting underway which will focus on transforming the electric grid management through improved understanding of asset risk, system risk, and optimal utilization of all grid assets. This specific project will address two main problems in grid management: 1) day-ahead operational reserves are often set based on heuristic rules that are disconnected from the real conditions of the assets and the system, and, 2) generation resources are scheduled without considering their impact on exacerbation or reduction of system risk. The Company has shared their dynamic reserve management methodology with the research team and looks forward to exploring improvement opportunities in these areas as the study progresses.

ADVANCING ZERO EMISSIONS LOAD FOLLOWING RESOURCE (ZELFR) TECHNOLOGY

> *"The key technologies the energy sector needs to reach net-zero emissions are known today, but not all of them are ready."* [2]

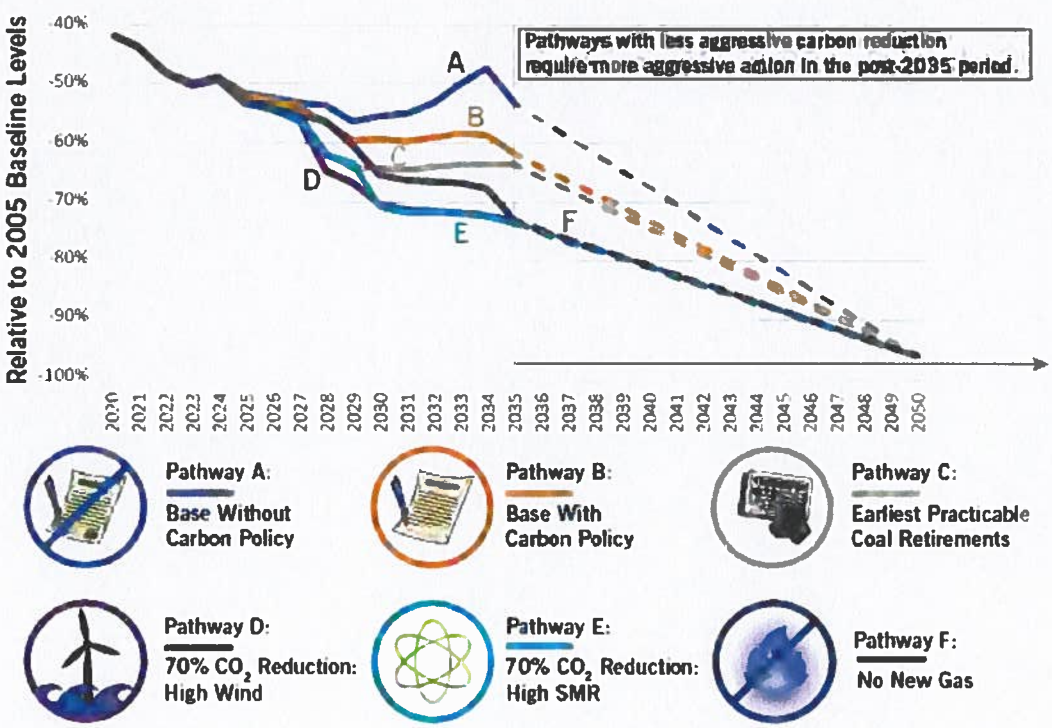
As noted in the Climate Report and in independent studies and reports, to reach deep carbon reductions, very low- or zero-emitting technologies that can be dispatched to meet energy demand over long durations will be needed to replace carbon emitting resources.[3] Innovation is a critical part of our path to achieving net-zero by 2050. With existing technologies, the Company can make important progress but cannot close the gap. To achieve net-zero, ZELFR technologies are needed that can respond to dynamic changes in both customer demand and renewable generation. The next decade is critical because these technologies need to be developed, demonstrated, refined and scaled on a very aggressive timeline to enable timely, cost-effective fossil retirements. While solar, wind and currently available energy storage have important roles to play now and in the future, as noted above their contribution begins to diminish as higher levels of renewable and storage penetration are reached, and resources capable of following load over long durations become increasingly needed to meet system capacity and energy needs reliably as fossil based resources are retired over time. ZELFRs will also ultimately be needed to replace the base load capability of existing nuclear units as they begin to retire in the 2050s and beyond. ZELFR technologies may include advanced nuclear; carbon capture, utilization and storage (CCUS); hydrogen and other gases; and long duration storage technologies such as molten salt, compressed/liquefied air, sub-surface pumped hydro, power to gas (e.g., hydrogen, discussed above) and advanced battery chemistries.

[2] IEA, Special Report on Clean Energy Innovation, Accelerating technology progress for a sustainable future.
[3] The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation, Nov. 18, 2018.

DUKE ENERGY CAROLINAS

The 70% reduction cases in this IRP rely on the accelerated adoption of offshore wind and small modular reactors (SMRs) – a ZELFR technology – along with a significant investment in storage. Of the three portfolios reflecting the most aggressive carbon reductions, portfolio E (70% Reduction with High SMRs) yielded the lowest customer cost impact. To be clear, the Company does not expect to build SMRs by 2030 but included SMRs to illustrate the importance of support for advancing these technologies as part of a balanced plan to achieve net-zero carbon. These more aggressive portfolio transitions are more costly but, as illustrated below, could position the portfolio well for future climate policy by accelerating deployment of advanced technologies, requiring less aggressive action after 2035 to reach net-zero.

FIGURE 16-B
CARBON REDUCTION TRAJECTORIES ON PATH TO NET-ZERO



Corrected 11.06.2020

The Company is actively engaged in industry efforts to support the development of ZELFRs. For example:

Advanced Nuclear: The Company has representatives on nuclear industry groups and advisory boards working on small modular reactor and advanced reactor technologies. The Company is also working with private and public sectors to drive research, development and demonstration of additional advanced reactor technologies under the DOE's Advanced Reactor Demonstration Program that supports innovative and diverse designs with the potential for commercialization in the mid-2030s.

Hydrogen/Other Gases: In addition to the research proposal with Siemens and Clemson University described earlier, the Company is a founding member of EPRI and GTI's Low Carbon Research Initiative. The overall goal of this initiative is to focus on fundamental advances in a variety of low-carbon electric generation technologies and low-carbon chemical energy carriers -- such as clean hydrogen, bioenergy, and renewable natural gas – which are needed to enable affordable pathways to economy-wide decarbonization.

Long Duration Energy Storage: As described earlier, Duke Energy has been involved with numerous battery energy storage pilots during the past 10 years. This has included active evaluation of long duration chemistries since 2016. The underlying chemistries of several pilots have the potential to provide daily or even seasonal energy storage, contributing to long duration storage applications in the future. Duke Energy will also increase the capacity at its Bad Creek facility in South Carolina by about 320 MW as it upgrades the facility. While this is not a pilot project, it represents an important contribution to our long duration storage capacity in the Carolinas.

Carbon Capture: Duke Energy has a similarly long history of engagement in CCUS research, including pilot scale projects and partnerships with the Electric Power Research Institute, the Department of Energy, national labs and others. One recent example is a partnership to perform an initial engineering design for a commercial-scale, membrane-based CO_2 capture system at Duke Energy's 600-MW East Bend power plant in Kentucky. Notably, deployment of carbon capture in the Carolinas would likely be dependent on interstate transportation infrastructure or innovative utilization opportunities due to a lack of suitable geology for CO_2 storage.

The Company will continue to monitor, evaluate and support the most promising emerging technologies to advance understanding and be prepared to act if more aggressive state or federal regulations CO_2 requirements are enacted.

THE NEED FOR SUPPORTIVE POLICIES

As shown by the Base without Carbon Policy pathway (A), from a modeling standpoint, carbon reductions could stall and reverse before reaching a 60% reduction in absence of policy to drive more aggressive additions of carbon-free resources. Carbon policy alone, however, is insufficient to address all the challenges associated with the dramatic transition of the grid and generation fleet to reach net-zero carbon, particularly for winter peaking, energy intensive Southeastern utilities. Federal policies are also critical to support and accelerate research, development, demonstration, and deployment of advanced technologies needed to meet this important goal. As noted in the Climate Report, for Duke Energy to achieve net-zero carbon emissions, the pace of interconnections over the next three decades is expected to be more than double that of the highest decade of generation growth in U.S. history, so the regulatory approvals of interconnection queue reform that the Company has been working on diligently with stakeholders over the last year is a critical hurdle. This pace of resource additions will also pose challenges for the interconnection-related transmission and distribution upgrades, transmission right-of-way acquisition, permitting, regulatory approval processes, supply chain, and generation siting as ideal sites are exhausted and suitable sites become increasingly scarce. These challenges are exacerbated if surrounding utilities are competing for the same resources to complete similar resource plans. It will be important to consider these factors and develop strategies to help create a supportive ecosystem for the deployment of carbon-free technologies and associated infrastructure as policymakers contemplate opportunities to accelerate the transition to net-zero while maintaining reliability and affordability for customers.

As described more fully in the 2020 Duke Energy Climate Report[4], policies will be increasingly important to support the changes required to transform the grid and drive advancement of carbon free resource technologies needed to reach the shared goal of net-zero carbon.

[4] https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en.